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# Draft Technical Report Project Description

Volume 1

## WyCoalGas Coal Gasification Project

Prepared for  
U.S. Bureau of Land Management

August 1981



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## WyCoalGas Coal Gasification Project

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**Woodward-Clyde Consultants**

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## TABLE OF CONTENTS

	<u>Page</u>
CHAPTER ONE INTRODUCTION	1-1
1.1 Project Organization	1-1
1.2 Summary of Proposed Action	1-3
1.3 Project Background	1-5
CHAPTER TWO PURPOSE AND NEED	2-1
2.1 Purpose of the Project	2-1
2.2 Need for Federal Action	2-4
CHAPTER THREE PROPOSED ACTION	3-1
3.1 General Description	3-1
3.2 Schedule and Workforce	3-1
3.3 Coal Gasification Plant	3-6
General Description	3-6
Coal Gasification Chemistry	3-12
Process Units	3-12
Support Units	3-26
Waste Water Recovery, Treatment, and Reuse	3-32
Control of Airborne Emissions	3-38
Solid Waste Management	3-39
Material Balance	3-55
Construction	3-55
Abandonment and Reclamation	3-63
3.4 Rochelle Coal Mine	3-68
General Description	3-68
Pre-production Activities	3-93
Mining and Associated Operations	3-102
Abandonment and Reclamation	3-125
3.5 Railroad	3-141
General Description	3-141
Construction Procedures	3-147
Railroad Operations	3-149
Abandonment and Reclamation	3-154
3.6 Water Supply System	3-156
General Description	3-156
Water Sources	3-159
Other System Components	3-164
Construction Procedures	3-174
Abandonment and Reclamation	3-181

TABLE OF CONTENTS

1-1	INTRODUCTION
1-2	1.1 Project Organization
1-3	1.2 Summary of Project Action
1-4	1.3 Project Background
2-1	CHAPTER TWO: PURPOSE AND SCOPE
2-2	2.1 Purpose of the Project
2-3	2.2 Scope for Project Action
3-1	CHAPTER THREE: TECHNICAL ACTION
3-2	3.1 General Description
3-3	3.2 Methods and Materials
3-4	3.3 Coal Gasification Plant
3-5	General Description
3-6	Coal Gasification Chemistry
3-7	Process Units
3-8	Support Units
3-9	Water Vapor Recovery, Treatment, and Reuse
3-10	Control of Airborne Emissions
3-11	Solid Waste Management
3-12	Material Balance
3-13	Costation
3-14	Abatement and Reclamation
3-15	Ecological Coal Mine
3-16	General Description
3-17	Pre-Production Activities
3-18	Water and Associated Operations
3-19	Abatement and Reclamation
3-20	3.4 Ecology
3-21	General Description
3-22	Construction Procedures
3-23	Relief Operations
3-24	Abatement and Reclamation
3-25	Water Supply System
3-26	Ecological Description
3-27	Water Reuse
3-28	Water System Components
3-29	Construction Procedures
3-30	Abatement and Reclamation

3.7	Product Pipeline	3-184
	General Description	3-184
	Construction Procedures	3-185
	Operation and Maintenance	3-198
	Abandonment and Reclamation	3-198
3.8	Electrical Supply System	3-199
		3-199
CHAPTER FOUR	AUTHORIZING ACTIONS	4-1
4.1	Federal	4-1
4.2	State	4-4
4.3	Other Jurisdictions	4-5
CHAPTER FIVE	ALTERNATIVES TO THE PROPOSED ACTION	5-1
5.1	Introduction	5-1
5.2	Alternatives Eliminated From Detailed Analysis	5-4
5.3	Alternatives Considered For Detailed Analysis	5-27
CHAPTER SIX	INTERRELATIONSHIPS WITH OTHER PROJECTS	6-1
6.1	Land Use Planning Policies	6-1
6.2	Existing and Future Projects in the Area	6-5
CHAPTER SEVEN	ENERGY EFFICIENCY ANALYSIS	7-1
7.1	Introduction	7-1
7.2	Analysis of Proposed Action	7-6
7.3	Analysis of Alternatives	7-18
REFERENCES		R-1
APPENDIX A	ESTIMATED ENERGY REQUIREMENTS, ROCHELLE MINE	A-1
APPENDIX B	STREAMS AFFECTED BY THE PROPOSED WYCOALGAS PROJECT	B-1
APPENDIX C-1	PLANT SITE STUDIES, BIOLOGICAL DATA	C-1
APPENDIX C-2	PLANT SITE STUDIES, ATMOSPHERIC DATA	C-83
APPENDIX C-3	PLANT SITE STUDIES, ARCHAEOLOGY	C-164
APPENDIX C-4	PLANT SITE STUDIES, SOCIO-ECONOMICS	C-185



## LIST OF FIGURES

<u>Figure</u>		<u>Page</u>
1.1-1	PROJECT LOCATION	1-2
3.1-1	COAL GASIFICATION COMPLEX-PROPOSED MAJOR FACILITIES	3-2
3.2-1	CONSTRUCTION SCHEDULE, WYCOALGAS PROJECT	3-5
3.3-1	GASIFICATION PLANT LOCATION	3-9
3.3-2	GASIFICATION PLANT SITE	3-10
3.3-3	GASIFICATION FACILITIES	3-11
3.3-4	ARTIST'S CONCEPT OF PLANT	3-13
3.3-5	SIMPLIFIED PROCESS FLOW DIAGRAM FOR COAL GASIFICATION	3-16
3.3-6	GASIFICATION PLANT COAL HANDLING AND PREPARATION FACILITIES	3-18
3.3-7	LURGI GAS PRODUCTION	3-19
3.3-8	TEXACO GASIFIER SYSTEM	3-22
3.3-9	WASTE WATER AND STORMWATER TREATMENT SYSTEM, GASIFICATION PLANT	3-34
3.3-10	CONSTRUCTION CAMP LOCATION, GASIFICATION PLANT	3-61
3.3-11	CONSTRUCTION CAMP DESIGN, GASIFICATION PLANT	3-62
3.4-1	ROCHELLE MINE LOCATION	3-69
3.4-2	ROCHELLE MINE PERMIT BOUNDARY	3-70
3.4-3	ROCHELLE MINE SURFACE OWNERSHIP	3-72
3.4-4	ROCHELLE MINE COAL OWNERSHIP	3-73
3.4-5(a)	GEOLOGIC CROSS SECTION 1	3-75
3.4-5(b)	GEOLOGIC CROSS SECTION 2	3-76
3.4-6	PROPOSED FACILITIES, ROCHELLE MINE	3-79
3.4-7	TYPICAL SIGNS AND MARKERS, ROCHELLE MINE	3-82
3.4-8	CONSTRUCTION SCHEDULE, ROCHELLE MINE	3-90
3.4-9	MINING SEQUENCE, ROCHELLE MINE	3-92
3.4-10	GENERALIZED ROAD SECTIONS, ROCHELLE MINE	3-95
3.4-11	SURFACE WATER CONTROL, ROCHELLE MINE	3-98
3.4-12	TYPICAL MINING SEQUENCE, ROCHELLE MINE	3-104
3.4-13	TYPICAL PIT CONFIGURATION, SOUTH MINING BLOCK	3-105
3.4-14	TYPICAL PIT CONFIGURATION, NORTH MINING BLOCK (West Panel)	3-106
3.4-15	LIMITS OF DISTURBANCE, ROCHELLE MINE	3-107
3.4-16	TOPSOIL SALVAGE SPECIFICATIONS, ROCHELLE MINE	3-111
3.4-17	OVERBURDEN PROGRESSION AND STOCKPILE LOCATION, ROCHELLE MINE	3-118
3.4-18	TYPICAL CROSS-SECTIONS OF OVERBURDEN STOCKPILES, ROCHELLE MINE	3-120
3.4-19	PROPOSED ASH DISPOSAL METHOD, ROCHELLE MINE	3-123
3.4-20	RECLAMATION SCHEDULE, ROCHELLE MINE	3-127
3.4-21	POST-MINING TOPOGRAPHY, ROCHELLE MINE	3-129



<u>Figure</u>		<u>Page</u>
3.5-1	COAL TRANSPORTATION RAILROAD	3-142
3.5-2	TYPICAL CROSS SECTION OF RAILROAD	3-145
3.5-3	TYPICAL SIDE ELEVATION	3-146
3.5-4	TYPICAL CUT AND FILL SECTIONS	3-150
3.5-5	TYPICAL ROAD CROSSINGS BY PROPOSED ELECTRIC RAILROAD	3-151
3.5-6	TYPICAL CULVERT DETAILS, ELECTRIC RAILROAD	3-152
3.6-1	NORTH WELL FIELD AND COMBS RESERVOIR LOCATION	3-157
3.6-2	SOUTH WELL FIELD, LAPRELE RESERVOIR, AND COMBS RESERVOIR LOCATION	3-158
3.6-3	COMBS RESERVOIR AND NORTH PLATTE DIVERSION FACILITY	3-167
3.6-4	ARTIST'S CONCEPTION, COMBS RESERVOIR AND DAM	3-168
3.6-5	NORTH PLATTE RIVER DIVERSION FACILITY	3-170
3.6-6	NORTH PLATTE INTAKE CHANNEL, PROFILE AND SECTION	3-172
3.6-7	WATER WELL DRILLING CONFIGURATION	3-177
3.7-1(a)	PRODUCT PIPELINE LOCATION	3-186
3.7-1(b)	PRODUCT PIPELINE LOCATION	3-187
3.7-1(c)	PRODUCT PIPELINE LOCATION	3-188
3.7-1(d)	PRODUCT PIPELINE LOCATION	3-189
3.7-2	TYPICAL PRODUCT PIPELINE CONSTRUCTION SPREAD	3-191
3.7-3	TYPICAL CONSTRUCTION RIGHT-OF-WAY CROSS SECTION	3-192
3.8-1	ELECTRIC POWER POLE WITH RAPTOR PROTECTION	3-201
5.2-1	LOCATION OF ALTERNATIVE PLANT SITES	5-10
5.2-2	COMPARISON OF SINGLE-STAGE AND TWO-STAGE CONSTRUCTION WORKFORCE	5-15
5.2-3	ALTERNATIVE PRODUCT PIPELINE ROUTES	5-23
5.3-1	BURLINGTON NORTHERN (BN) RAILROAD ROUTES	5-28
5.3-2	MINE RAIL SPUR, COAL TRANSPORTATION ALTERNATIVE	5-30
6.2-1	EXISTING PROJECTS IN THE WYCOALGAS PROJECT VICINITY	6-10
6.2-2	FUTURE PROJECTS IN THE WYCOALGAS PROJECT VICINITY	6-11
7.1-1	SYSTEM FLOW FOR ENERGY EFFICIENCY ANALYSIS OF WYCOALGAS GASIFICATION PROJECT	7-3
3.4-1	WATER QUALITY ANALYSIS, WYCOALGAS PROJECT	3-42
3.4-2	WATER QUALITY ANALYSIS, WYCOALGAS PROJECT	3-43
3.4-3	WATER QUALITY ANALYSIS, WYCOALGAS PROJECT	3-44
3.4-4	WATER QUALITY ANALYSIS, WYCOALGAS PROJECT	3-45
3.4-5	WATER QUALITY ANALYSIS, WYCOALGAS PROJECT	3-46
3.4-6	WATER QUALITY ANALYSIS, WYCOALGAS PROJECT	3-47
3.4-7	WATER QUALITY ANALYSIS, WYCOALGAS PROJECT	3-48
3.4-8	WATER QUALITY ANALYSIS, WYCOALGAS PROJECT	3-49
3.4-9	WATER QUALITY ANALYSIS, WYCOALGAS PROJECT	3-50
3.4-10	WATER QUALITY ANALYSIS, WYCOALGAS PROJECT	3-51
3.4-11	WATER QUALITY ANALYSIS, WYCOALGAS PROJECT	3-52
3.4-12	WATER QUALITY ANALYSIS, WYCOALGAS PROJECT	3-53
3.4-13	WATER QUALITY ANALYSIS, WYCOALGAS PROJECT	3-54
3.4-14	WATER QUALITY ANALYSIS, WYCOALGAS PROJECT	3-55
3.4-15	WATER QUALITY ANALYSIS, WYCOALGAS PROJECT	3-56
3.4-16	WATER QUALITY ANALYSIS, WYCOALGAS PROJECT	3-57
3.4-17	WATER QUALITY ANALYSIS, WYCOALGAS PROJECT	3-58
3.4-18	WATER QUALITY ANALYSIS, WYCOALGAS PROJECT	3-59
3.4-19	WATER QUALITY ANALYSIS, WYCOALGAS PROJECT	3-60
3.4-20	WATER QUALITY ANALYSIS, WYCOALGAS PROJECT	3-61
3.4-21	WATER QUALITY ANALYSIS, WYCOALGAS PROJECT	3-62
3.4-22	WATER QUALITY ANALYSIS, WYCOALGAS PROJECT	3-63
3.4-23	WATER QUALITY ANALYSIS, WYCOALGAS PROJECT	3-64
3.4-24	WATER QUALITY ANALYSIS, WYCOALGAS PROJECT	3-65
3.4-25	WATER QUALITY ANALYSIS, WYCOALGAS PROJECT	3-66
3.4-26	WATER QUALITY ANALYSIS, WYCOALGAS PROJECT	3-67
3.4-27	WATER QUALITY ANALYSIS, WYCOALGAS PROJECT	3-68
3.4-28	WATER QUALITY ANALYSIS, WYCOALGAS PROJECT	3-69
3.4-29	WATER QUALITY ANALYSIS, WYCOALGAS PROJECT	3-70
3.4-30	WATER QUALITY ANALYSIS, WYCOALGAS PROJECT	3-71
3.4-31	WATER QUALITY ANALYSIS, WYCOALGAS PROJECT	3-72
3.4-32	WATER QUALITY ANALYSIS, WYCOALGAS PROJECT	3-73
3.4-33	WATER QUALITY ANALYSIS, WYCOALGAS PROJECT	3-74
3.4-34	WATER QUALITY ANALYSIS, WYCOALGAS PROJECT	3-75
3.4-35	WATER QUALITY ANALYSIS, WYCOALGAS PROJECT	3-76
3.4-36	WATER QUALITY ANALYSIS, WYCOALGAS PROJECT	3-77
3.4-37	WATER QUALITY ANALYSIS, WYCOALGAS PROJECT	3-78
3.4-38	WATER QUALITY ANALYSIS, WYCOALGAS PROJECT	3-79
3.4-39	WATER QUALITY ANALYSIS, WYCOALGAS PROJECT	3-80
3.4-40	WATER QUALITY ANALYSIS, WYCOALGAS PROJECT	3-81
3.4-41	WATER QUALITY ANALYSIS, WYCOALGAS PROJECT	3-82
3.4-42	WATER QUALITY ANALYSIS, WYCOALGAS PROJECT	3-83
3.4-43	WATER QUALITY ANALYSIS, WYCOALGAS PROJECT	3-84
3.4-44	WATER QUALITY ANALYSIS, WYCOALGAS PROJECT	3-85
3.4-45	WATER QUALITY ANALYSIS, WYCOALGAS PROJECT	3-86
3.4-46	WATER QUALITY ANALYSIS, WYCOALGAS PROJECT	3-87
3.4-47	WATER QUALITY ANALYSIS, WYCOALGAS PROJECT	3-88
3.4-48	WATER QUALITY ANALYSIS, WYCOALGAS PROJECT	3-89
3.4-49	WATER QUALITY ANALYSIS, WYCOALGAS PROJECT	3-90
3.4-50	WATER QUALITY ANALYSIS, WYCOALGAS PROJECT	3-91
3.4-51	WATER QUALITY ANALYSIS, WYCOALGAS PROJECT	3-92
3.4-52	WATER QUALITY ANALYSIS, WYCOALGAS PROJECT	3-93
3.4-53	WATER QUALITY ANALYSIS, WYCOALGAS PROJECT	3-94
3.4-54	WATER QUALITY ANALYSIS, WYCOALGAS PROJECT	3-95
3.4-55	WATER QUALITY ANALYSIS, WYCOALGAS PROJECT	3-96
3.4-56	WATER QUALITY ANALYSIS, WYCOALGAS PROJECT	3-97
3.4-57	WATER QUALITY ANALYSIS, WYCOALGAS PROJECT	3-98
3.4-58	WATER QUALITY ANALYSIS, WYCOALGAS PROJECT	3-99
3.4-59	WATER QUALITY ANALYSIS, WYCOALGAS PROJECT	3-100

Index		Index
1-151	COAL TRANSPORTATION RAILROAD	1-1-1
1-152	TYPICAL CROSS SECTION OF RAILROAD	1-1-2
1-153	TYPICAL SIDE ELEVATION	1-1-3
1-154	TYPICAL CUT AND FILL SECTION	1-1-4
1-155	TYPICAL ROAD CROSSLINK BY TYPICAL ELEVATION	1-1-5
1-156	RAILROAD	1-1-6
1-157	TYPICAL GROUND PROFILE, TYPICAL RAILROAD	1-1-7
1-158	NORTH WELL FIELD AND CROSS RAILROAD LOCATION	1-1-8
1-159	NORTH WELL FIELD, TYPICAL RAILROAD, AND	1-1-9
1-160	COAL RAILROAD LOCATION	1-1-10
1-161	COAL RAILROAD AND NORTH WELL FIELD ELEVATION	1-1-11
1-162	TACTICS	1-1-12
1-163	AGRICULTURE, COAL RAILROAD AND DAN	1-1-13
1-164	WHITE WATERS RIVER TOWNSHIP TACTICS	1-1-14
1-165	WHITE WATERS TOWNSHIP, TACTICS AND SECTION	1-1-15
1-166	WHITE WATERS TOWNSHIP TACTICS	1-1-16
1-167	WHITE WATERS TOWNSHIP TACTICS	1-1-17
1-168	WHITE WATERS TOWNSHIP TACTICS	1-1-18
1-169	WHITE WATERS TOWNSHIP TACTICS	1-1-19
1-170	WHITE WATERS TOWNSHIP TACTICS	1-1-20
1-171	WHITE WATERS TOWNSHIP TACTICS	1-1-21
1-172	WHITE WATERS TOWNSHIP TACTICS	1-1-22
1-173	WHITE WATERS TOWNSHIP TACTICS	1-1-23
1-174	WHITE WATERS TOWNSHIP TACTICS	1-1-24
1-175	WHITE WATERS TOWNSHIP TACTICS	1-1-25
1-176	WHITE WATERS TOWNSHIP TACTICS	1-1-26
1-177	WHITE WATERS TOWNSHIP TACTICS	1-1-27
1-178	WHITE WATERS TOWNSHIP TACTICS	1-1-28
1-179	WHITE WATERS TOWNSHIP TACTICS	1-1-29
1-180	WHITE WATERS TOWNSHIP TACTICS	1-1-30
1-181	WHITE WATERS TOWNSHIP TACTICS	1-1-31
1-182	WHITE WATERS TOWNSHIP TACTICS	1-1-32
1-183	WHITE WATERS TOWNSHIP TACTICS	1-1-33
1-184	WHITE WATERS TOWNSHIP TACTICS	1-1-34
1-185	WHITE WATERS TOWNSHIP TACTICS	1-1-35
1-186	WHITE WATERS TOWNSHIP TACTICS	1-1-36
1-187	WHITE WATERS TOWNSHIP TACTICS	1-1-37
1-188	WHITE WATERS TOWNSHIP TACTICS	1-1-38
1-189	WHITE WATERS TOWNSHIP TACTICS	1-1-39
1-190	WHITE WATERS TOWNSHIP TACTICS	1-1-40
1-191	WHITE WATERS TOWNSHIP TACTICS	1-1-41
1-192	WHITE WATERS TOWNSHIP TACTICS	1-1-42
1-193	WHITE WATERS TOWNSHIP TACTICS	1-1-43
1-194	WHITE WATERS TOWNSHIP TACTICS	1-1-44
1-195	WHITE WATERS TOWNSHIP TACTICS	1-1-45
1-196	WHITE WATERS TOWNSHIP TACTICS	1-1-46
1-197	WHITE WATERS TOWNSHIP TACTICS	1-1-47
1-198	WHITE WATERS TOWNSHIP TACTICS	1-1-48
1-199	WHITE WATERS TOWNSHIP TACTICS	1-1-49
1-200	WHITE WATERS TOWNSHIP TACTICS	1-1-50
1-201	WHITE WATERS TOWNSHIP TACTICS	1-1-51
1-202	WHITE WATERS TOWNSHIP TACTICS	1-1-52
1-203	WHITE WATERS TOWNSHIP TACTICS	1-1-53
1-204	WHITE WATERS TOWNSHIP TACTICS	1-1-54
1-205	WHITE WATERS TOWNSHIP TACTICS	1-1-55
1-206	WHITE WATERS TOWNSHIP TACTICS	1-1-56
1-207	WHITE WATERS TOWNSHIP TACTICS	1-1-57
1-208	WHITE WATERS TOWNSHIP TACTICS	1-1-58
1-209	WHITE WATERS TOWNSHIP TACTICS	1-1-59
1-210	WHITE WATERS TOWNSHIP TACTICS	1-1-60
1-211	WHITE WATERS TOWNSHIP TACTICS	1-1-61
1-212	WHITE WATERS TOWNSHIP TACTICS	1-1-62
1-213	WHITE WATERS TOWNSHIP TACTICS	1-1-63
1-214	WHITE WATERS TOWNSHIP TACTICS	1-1-64
1-215	WHITE WATERS TOWNSHIP TACTICS	1-1-65
1-216	WHITE WATERS TOWNSHIP TACTICS	1-1-66
1-217	WHITE WATERS TOWNSHIP TACTICS	1-1-67
1-218	WHITE WATERS TOWNSHIP TACTICS	1-1-68
1-219	WHITE WATERS TOWNSHIP TACTICS	1-1-69
1-220	WHITE WATERS TOWNSHIP TACTICS	1-1-70
1-221	WHITE WATERS TOWNSHIP TACTICS	1-1-71
1-222	WHITE WATERS TOWNSHIP TACTICS	1-1-72
1-223	WHITE WATERS TOWNSHIP TACTICS	1-1-73
1-224	WHITE WATERS TOWNSHIP TACTICS	1-1-74
1-225	WHITE WATERS TOWNSHIP TACTICS	1-1-75
1-226	WHITE WATERS TOWNSHIP TACTICS	1-1-76
1-227	WHITE WATERS TOWNSHIP TACTICS	1-1-77
1-228	WHITE WATERS TOWNSHIP TACTICS	1-1-78
1-229	WHITE WATERS TOWNSHIP TACTICS	1-1-79
1-230	WHITE WATERS TOWNSHIP TACTICS	1-1-80
1-231	WHITE WATERS TOWNSHIP TACTICS	1-1-81
1-232	WHITE WATERS TOWNSHIP TACTICS	1-1-82
1-233	WHITE WATERS TOWNSHIP TACTICS	1-1-83
1-234	WHITE WATERS TOWNSHIP TACTICS	1-1-84
1-235	WHITE WATERS TOWNSHIP TACTICS	1-1-85
1-236	WHITE WATERS TOWNSHIP TACTICS	1-1-86
1-237	WHITE WATERS TOWNSHIP TACTICS	1-1-87
1-238	WHITE WATERS TOWNSHIP TACTICS	1-1-88
1-239	WHITE WATERS TOWNSHIP TACTICS	1-1-89
1-240	WHITE WATERS TOWNSHIP TACTICS	1-1-90
1-241	WHITE WATERS TOWNSHIP TACTICS	1-1-91
1-242	WHITE WATERS TOWNSHIP TACTICS	1-1-92
1-243	WHITE WATERS TOWNSHIP TACTICS	1-1-93
1-244	WHITE WATERS TOWNSHIP TACTICS	1-1-94
1-245	WHITE WATERS TOWNSHIP TACTICS	1-1-95
1-246	WHITE WATERS TOWNSHIP TACTICS	1-1-96
1-247	WHITE WATERS TOWNSHIP TACTICS	1-1-97
1-248	WHITE WATERS TOWNSHIP TACTICS	1-1-98
1-249	WHITE WATERS TOWNSHIP TACTICS	1-1-99
1-250	WHITE WATERS TOWNSHIP TACTICS	1-1-100

## LIST OF TABLES

<u>Table</u>		<u>Page</u>
2.1-1	SUPPLY/DEMAND FORECASTS FOR GAS IN THE PANHANDLE EASTERN SYSTEM (billion cubic feet)	2-5
3.1-1	ACREAGE REQUIREMENTS, WYCOALGAS PROJECT	3-3
3.1-2	LAND OWNERSHIP, WYCOALGAS PROJECT	3-4
3.2-1	APPROXIMATE AVERAGE WYCOALGAS PROJECT WORKFORCE BY YEAR	3-7
3.2-2	APPROXIMATE AVERAGE MONTHLY PAYROLLS, WYCOALGAS PROJECT (Thousands of 1981 dollars)	3-8
3.3-1	PRIMARY GASIFICATION REACTIONS, LURGI PROCESS	3-14
3.3-2	PRODUCT GAS COMPOSITION	3-15
3.3-3	OVERALL 300 MMSCFD PLANT COAL BALANCE	3-15
3.3-4	SUMMARY WATER BALANCE FOR COAL GASIFICATION PLANT OPERATION	3-27
3.3-5	SUMMARY OF THE STORAGE FACILITIES OF THE WYCOALGAS COMPLEX	3-31
3.3-6	QUANTITY AND NATURE OF MAJOR WASTE WATER STREAMS	3-33
3.3-7	SUMMARY OF EMISSION CONTROL EQUIPMENT, GASIFICATION PLANT	3-40
3.3-8	SOLID WASTES FROM 300 MMSCFD GASIFICATION PLANT	3-42
3.3-9	ROSEBUD COAL - GASIFIER ASH COMPOSITION	3-43
3.3-10	RESULTS OF RCRA EP TOXICITY TESTING ON SOLID WASTES ROUTED TO THE INTERIM STORAGE AREA (mg/l)	3-45
3.3-11	RESULTS OF WATER QUALITY ANALYSIS ON NEUTRAL LEACHATE	3-46
3.3-12	AVERAGE MINERAL ANALYSIS OF ROCHELLE COAL ASH (weight percent)	3-47
3.3-13	WATER TREATMENT SLUDGE COMPOSITION (weight percent)	3-50
3.3-14	OVERALL MATERIAL BALANCE, 300 MMSCFD PLANT	3-56
3.3-15	LURGI AND TEXACO GASIFICATION OUTPUT	3-57
3.3-16	MAJOR EQUIPMENT REQUIREMENTS FOR GASIFICATION PLANT CONSTRUCTION	3-60
3.3-17	STOCKPILE AND RECLAMATION SEED MIXTURE, GASIFICATION PLANT	3-66
3.4-1	AREA AFFECTED BY ROCHELLE COAL MINE FEDERAL COAL LEASE NO. W-0321779	3-71
3.4-2	ROLAND COAL ANALYSIS, ROCHELLE MINE	3-77
3.4-3	ELECTRICAL REQUIREMENTS, ROCHELLE MINE OPERATION	3-85
3.4-4	DIESEL FUEL REQUIREMENTS, ROCHELLE MINE OPERATION	3-86
3.4-5	WATER REQUIREMENTS, ROCHELLE MINE OPERATION	3-87
3.4-6	PRODUCTION SCHEDULE, ROCHELLE MINE	3-91
3.4-7	ROAD DESIGN SPECIFICATIONS, ROCHELLE MINE	3-94
3.4-8	SEDIMENTATION PONDS AND DISCHARGE LOCATIONS, ROCHELLE MINE	3-100



<u>Table</u>		<u>Page</u>
3.4-9	MINING AND RECLAMATION EQUIPMENT, ROCHELLE MINE (Initial Five-Year Period)	3-110
3.4-10	SEED MIXES FOR THE ROCHELLE COAL MINE AREA	3-132
3.4-11	SUBSTITUTE SEED SPECIES	3-137
3.5-1	RAILROAD CHARACTERISTICS	3-143
3.5-2	MAJOR EQUIPMENT REQUIREMENTS FOR RAILROAD CONSTRUCTION	3-153
3.6-1	OPERATING PERMITS, LAPRELE RESERVOIR	3-160
3.6-2	COMBS RESERVOIR STORAGE RIGHT FILINGS	3-166
3.6-3	EQUIPMENT REQUIRED FOR RESERVOIR CONSTRUCTION	3-175
3.6-4	EQUIPMENT REQUIRED FOR PIPELINE CONSTRUCTION	3-180
3.6-5	WATERBREAK GUIDELINES, PROPOSED WATER PIPELINES	3-183
3.7-1	PRODUCT PIPELINE CONSTRUCTION EQUIPMENT IN A TYPICAL SPREAD	3-193
5.1-1	IDENTIFIED ALTERNATIVES TO THE PROPOSED ACTION	5-2
5.1-2	SUMMARY OF SCREENING DECISIONS FOR ALTERNATIVES	5-5
5.2-1	THIRD GENERATION COAL GASIFICATION PROCESSES	5-12
5.2-2	COMPARISON OF EMISSIONS FROM DIESEL LOCOMOTIVE AND ELECTRIC LOCOMOTIVE POWER SOURCE (tons/year)	5-18
5.2-3	ALTERNATIVE PRODUCT PIPELINE ROUTES	5-24
6.2-1	EXISTING ENERGY AND RESOURCE RELATED PROJECTS IN THE VICINITY OF THE PROPOSED PROJECT	6-6
6.2-2	FUTURE ENERGY AND RESOURCE RELATED PROJECTS IN THE VICINITY OF THE PROPOSED PROJECT	6-8
7.1-1	SUMMARY OF ENERGY EFFICIENCY ANALYSIS BOUNDARIES	7-4
7.1-2	ENERGY CONVERSION FACTORS	7-5
7.2-1	PURCHASED ENERGY, ROCHELLE MINE	7-8
7.2-2	DISTRIBUTION OF EMPLOYEES AT MINE	7-9
7.2-3	SUMMARY OF COAL MINE ENERGY EFFICIENCY ANALYSIS	7-10
7.2-4	SUMMARY OF RAILROAD EFFICIENCY ANALYSIS	7-11
7.2-5	DISTRIBUTION OF EMPLOYEES AT PLANT	7-13
7.2-6	COAL GASIFICATION BY-PRODUCTS AND HEAT CONTENT	7-14
7.2-7	SUMMARY OF PLANT ENERGY EFFICIENCY ANALYSIS	7-16
7.2-8	BY-PRODUCT SHIPPING ENERGY REQUIREMENTS	7-17
7.2-9	SUMMARY OF ENERGY EFFICIENCY ANALYSIS OF PROPOSED ACTION	7-19
7.3-1	ENERGY EFFICIENCY COMPARISON: COAL TRANSPOR- TATION ON BURLINGTON NORTHERN (BN)	7-20
7.3-2	APPROXIMATE DISTANCES OF AREA MINES FROM PROPOSED PLANT	7-22
7.3-3	SUMMARY OF ADDITIONAL ENERGY REQUIREMENTS FOR ALTERNATE COAL SUPPLIES	7-23
7.3-4	ENERGY EFFICIENCY COMPARISON: ELECTRICITY PRODUCTION USING COAL FINES	7-25

Page	Table
1-10	1-1-1
1-11	1-1-2
1-12	1-1-3
1-13	1-1-4
1-14	1-1-5
1-15	1-1-6
1-16	1-1-7
1-17	1-1-8
1-18	1-1-9
1-19	1-1-10
1-20	1-1-11
1-21	1-1-12
1-22	1-1-13
1-23	1-1-14
1-24	1-1-15
1-25	1-1-16
1-26	1-1-17
1-27	1-1-18
1-28	1-1-19
1-29	1-1-20
1-30	1-1-21
1-31	1-1-22
1-32	1-1-23
1-33	1-1-24
1-34	1-1-25
1-35	1-1-26
1-36	1-1-27
1-37	1-1-28
1-38	1-1-29
1-39	1-1-30
1-40	1-1-31
1-41	1-1-32
1-42	1-1-33
1-43	1-1-34
1-44	1-1-35
1-45	1-1-36
1-46	1-1-37
1-47	1-1-38
1-48	1-1-39
1-49	1-1-40
1-50	1-1-41
1-51	1-1-42
1-52	1-1-43
1-53	1-1-44
1-54	1-1-45
1-55	1-1-46
1-56	1-1-47
1-57	1-1-48
1-58	1-1-49
1-59	1-1-50
1-60	1-1-51
1-61	1-1-52
1-62	1-1-53
1-63	1-1-54
1-64	1-1-55
1-65	1-1-56
1-66	1-1-57
1-67	1-1-58
1-68	1-1-59
1-69	1-1-60
1-70	1-1-61
1-71	1-1-62
1-72	1-1-63
1-73	1-1-64
1-74	1-1-65
1-75	1-1-66
1-76	1-1-67
1-77	1-1-68
1-78	1-1-69
1-79	1-1-70
1-80	1-1-71
1-81	1-1-72
1-82	1-1-73
1-83	1-1-74
1-84	1-1-75
1-85	1-1-76
1-86	1-1-77
1-87	1-1-78
1-88	1-1-79
1-89	1-1-80
1-90	1-1-81
1-91	1-1-82
1-92	1-1-83
1-93	1-1-84
1-94	1-1-85
1-95	1-1-86
1-96	1-1-87
1-97	1-1-88
1-98	1-1-89
1-99	1-1-90
2-1	1-1-91
2-2	1-1-92
2-3	1-1-93
2-4	1-1-94
2-5	1-1-95
2-6	1-1-96
2-7	1-1-97
2-8	1-1-98
2-9	1-1-99
2-10	1-1-100
2-11	1-1-101
2-12	1-1-102
2-13	1-1-103
2-14	1-1-104
2-15	1-1-105
2-16	1-1-106
2-17	1-1-107
2-18	1-1-108
2-19	1-1-109
2-20	1-1-110
2-21	1-1-111
2-22	1-1-112
2-23	1-1-113
2-24	1-1-114
2-25	1-1-115
2-26	1-1-116
2-27	1-1-117
2-28	1-1-118
2-29	1-1-119
2-30	1-1-120
2-31	1-1-121
2-32	1-1-122
2-33	1-1-123
2-34	1-1-124
2-35	1-1-125
2-36	1-1-126
2-37	1-1-127
2-38	1-1-128
2-39	1-1-129
2-40	1-1-130
2-41	1-1-131
2-42	1-1-132
2-43	1-1-133
2-44	1-1-134
2-45	1-1-135
2-46	1-1-136
2-47	1-1-137
2-48	1-1-138
2-49	1-1-139
2-50	1-1-140
2-51	1-1-141
2-52	1-1-142
2-53	1-1-143
2-54	1-1-144
2-55	1-1-145
2-56	1-1-146
2-57	1-1-147
2-58	1-1-148
2-59	1-1-149
2-60	1-1-150
2-61	1-1-151
2-62	1-1-152
2-63	1-1-153
2-64	1-1-154
2-65	1-1-155
2-66	1-1-156
2-67	1-1-157
2-68	1-1-158
2-69	1-1-159
2-70	1-1-160
2-71	1-1-161
2-72	1-1-162
2-73	1-1-163
2-74	1-1-164
2-75	1-1-165
2-76	1-1-166
2-77	1-1-167
2-78	1-1-168
2-79	1-1-169
2-80	1-1-170
2-81	1-1-171
2-82	1-1-172
2-83	1-1-173
2-84	1-1-174
2-85	1-1-175
2-86	1-1-176
2-87	1-1-177
2-88	1-1-178
2-89	1-1-179
2-90	1-1-180
2-91	1-1-181
2-92	1-1-182
2-93	1-1-183
2-94	1-1-184
2-95	1-1-185
2-96	1-1-186
2-97	1-1-187
2-98	1-1-188
2-99	1-1-189
3-1	1-1-190
3-2	1-1-191
3-3	1-1-192
3-4	1-1-193
3-5	1-1-194
3-6	1-1-195
3-7	1-1-196
3-8	1-1-197
3-9	1-1-198
3-10	1-1-199
3-11	1-1-200
3-12	1-1-201
3-13	1-1-202
3-14	1-1-203
3-15	1-1-204
3-16	1-1-205
3-17	1-1-206
3-18	1-1-207
3-19	1-1-208
3-20	1-1-209
3-21	1-1-210
3-22	1-1-211
3-23	1-1-212
3-24	1-1-213
3-25	1-1-214
3-26	1-1-215
3-27	1-1-216
3-28	1-1-217
3-29	1-1-218
3-30	1-1-219
3-31	1-1-220
3-32	1-1-221
3-33	1-1-222
3-34	1-1-223
3-35	1-1-224
3-36	1-1-225
3-37	1-1-226
3-38	1-1-227
3-39	1-1-228
3-40	1-1-229
3-41	1-1-230
3-42	1-1-231
3-43	1-1-232
3-44	1-1-233
3-45	1-1-234
3-46	1-1-235
3-47	1-1-236
3-48	1-1-237
3-49	1-1-238
3-50	1-1-239
3-51	1-1-240
3-52	1-1-241
3-53	1-1-242
3-54	1-1-243
3-55	1-1-244
3-56	1-1-245
3-57	1-1-246
3-58	1-1-247
3-59	1-1-248
3-60	1-1-249
3-61	1-1-250
3-62	1-1-251
3-63	1-1-252
3-64	1-1-253
3-65	1-1-254
3-66	1-1-255
3-67	1-1-256
3-68	1-1-257
3-69	1-1-258
3-70	1-1-259
3-71	1-1-260
3-72	1-1-261
3-73	1-1-262
3-74	1-1-263
3-75	1-1-264
3-76	1-1-265
3-77	1-1-266
3-78	1-1-267
3-79	1-1-268
3-80	1-1-269
3-81	1-1-270
3-82	1-1-271
3-83	1-1-272
3-84	1-1-273
3-85	1-1-274
3-86	1-1-275
3-87	1-1-276
3-88	1-1-277
3-89	1-1-278
3-90	1-1-279
3-91	1-1-280
3-92	1-1-281
3-93	1-1-282
3-94	1-1-283
3-95	1-1-284
3-96	1-1-285
3-97	1-1-286
3-98	1-1-287
3-99	1-1-288
4-1	1-1-289
4-2	1-1-290
4-3	1-1-291
4-4	1-1-292
4-5	1-1-293
4-6	1-1-294
4-7	1-1-295
4-8	1-1-296
4-9	1-1-297
4-10	1-1-298
4-11	1-1-299
4-12	1-1-300
4-13	1-1-301
4-14	1-1-302
4-15	1-1-303
4-16	1-1-304
4-17	1-1-305
4-18	1-1-306
4-19	1-1-307
4-20	1-1-308
4-21	1-1-309
4-22	1-1-310
4-23	1-1-311
4-24	1-1-312
4-25	1-1-313
4-26	1-1-314
4-27	1-1-315
4-28	1-1-316
4-29	1-1-317
4-30	1-1-318
4-31	1-1-319
4-32	1-1-320
4-33	1-1-321
4-34	1-1-322
4-35	1-1-323
4-36	1-1-324
4-37	1-1-325
4-38	1-1-326
4-39	1-1-327
4-40	1-1-328
4-41	1-1-329
4-42	1-1-330
4-43	1-1-331
4-44	1-1-332
4-45	1-1-333
4-46	1-1-334
4-47	1-1-335
4-48	1-1-336
4-49	1-1-337
4-50	1-1-338
4-51	1-1-339
4-52	1-1-340
4-53	1-1-341
4-54	1-1-342
4-55	1-1-343
4-56	1-1-344
4-57	1-1-345
4-58	1-1-346
4-59	1-1-347
4-60	1-1-348
4-61	1-1-349
4-62	1-1-350
4-63	1-1-351
4-64	1-1-352
4-65	1-1-353
4-66	1-1-354
4-67	1-1-355
4-68	1-1-356
4-69	1-1-357
4-70	1-1-358
4-71	1-1-359
4-72	1-1-360
4-73	1-1-361
4-74	1-1-362
4-75	1-1-363
4-76	1-1-364
4-77	1-1-365
4-78	1-1-366
4-79	1-1-367
4-80	1-1-368
4-81	1-1-369
4-82	1-1-370
4-83	1-1-371
4-84	1-1-372
4-85	1-1-373
4-86	1-1-374
4-87	1-1-375
4-88	1-1-376
4-89	1-1-377
4-90	1-1-378
4-91	1-1-379
4-92	1-1-380
4-93	1-1-381
4-94	1-1-382
4-95	1-1-383
4-96	1-1-384
4-97	1-1-385
4-98	1-1-386
4-99	1-1-387
5-1	1-1-388
5-2	1-1-389
5-3	1-1-390
5-4	1-1-391
5-5	1-1-392
5-6	1-1-393
5-7	1-1-394
5-8	1-1-395
5-9	1-1-396
5-10	1-1-397
5-11	1-1-398
5-12	1-1-399
5-13	1-1-400
5-14	1-1-401
5-15	1-1-402
5-16	1-1-403
5-17	1-1-404
5-18	1-1-405
5-19	1-1-406
5-20	1-1-407
5-21	1-1-408
5-22	1-1-409
5-23	1-1-410
5-24	1-1-411
5-25	1-1-412
5-26	1-1-413
5-27	1-1-414
5-28	1-1-415
5-29	1-1-416

## Chapter 1

### INTRODUCTION

WyCoalGas, Inc., a wholly owned subsidiary of Panhandle Eastern Corporation (PEC), proposes to construct a full-scale commercial high-Btu coal gasification plant in Converse County, Wyoming. In addition to the plant, a dedicated coal mine, a coal transportation system, a water supply system, and a product pipeline are included in the total project description for environmental assessment. Locations of these proposed facilities are presented in Figure 1.1-1.

#### 1.1 Project Organization

Along with WyCoalGas, Inc., Pacific Gas and Electric Co. (PG&E), and Ruhrgas Carbon Conversion, Inc. (RUCON) are sponsors of the proposed project. PG&E and RUCON have joined with WyCoalGas, Inc., in an interim agreement to contribute funds to the development of the project, and are actively involved in the completion of a partnership agreement. A subsidiary of PEC, Panhandle Eastern Pipe Line Company, and a subsidiary of PG&E propose to purchase the product synthetic pipeline gas (SPG); the purchase agreement has not yet been completed. RUCON would not purchase any of the gas, although it would provide a portion of the equity investment.

Rochelle Coal Company, a joint venture of Pan Eastern Coal (a subsidiary of PEC) and Powder River Coal Company (a subsidiary of Peabody Coal Co.) would have the responsibility of permitting and managing the dedicated coal mine known as the Rochelle Mine. Operation of the mine would be the responsibility of the Peabody Coal Company.

Exhibit 1  
MEMORANDUM

Wyckoff, Inc., a wholly owned subsidiary of American Electric  
Corporation (AEC), proposes to construct a fully-automated  
high-pressure gas liquefaction plant in Gwynedd, Pennsylvania. In  
addition to the plant, a dedicated coal mine, a coal transportation  
system, a water supply system, and a product pipeline are included in  
the total project. Detailed information has been submitted to the  
of these proposed facilities are presented in Figure 1-1.

1.1 Project Description

Along with Wyckoff, Inc., Pacific Gas and Electric Co. (PG&E),  
and Oregon Carbon Conversion, Inc. (OCC) are sponsors of the pro-  
posed project. PG&E and OCC have entered into a partnership in the pro-  
posed project. PG&E is responsible for the development of the pro-  
ject, and is actively involved in the operation of a partnership  
agreement. A subsidiary of PG&E, Pacific Gas and Electric Co.,  
and a subsidiary of OCC propose to purchase the product gas  
pipeline gas (LPG). The purchase agreement has not yet been completed.  
PG&E would not purchase any of the gas, although it would provide a  
portion of the equity investment.

Pacific Gas and Electric Co., a joint venture of the Pacific Gas &  
Electric Co. (PG&E) and Portland River Coal Company is a subsidiary of  
Portland River Coal Co. (PRC) would have the responsibility of permitting and  
managing the dedicated coal mine known as the Pacific Gas &  
Electric Co. mine would be the responsibility of the Portland River  
Company.





## 1.2 Summary of Proposed Action

Project Components and Location. The coal gasification plant would be located approximately 16 miles northeast of Douglas, Wyoming. Commercially proven Lurgi and Texaco gasification technologies would be used to produce a nominal 300 million standard cubic feet per day (MMSCFD) of synthetic pipeline gas (SPG) with a heating value in the range of 950 to 960 Btu per cubic foot. At this designed production and heating value, the plant would produce the equivalent of approximately 300 billion Btu per day or 100 trillion Btu per year.

Coal for gasification would be supplied from the Rochelle Mine, a proposed surface mine located approximately 40 miles north of the proposed plant site, in southeast Campbell County, Wyoming. At full capacity the mine would supply 11 million tons of coal per year to the plant. Estimated coal reserves at the Rochelle Mine are in excess of 500 million tons of subbituminous coal. The coal would be mined in a truck and shovel operation.

Delivery of the coal to the gasification plant would be by a 40-mile electric railroad. The railroad and rolling stock would be owned by WyCoalGas. Unit trains consisting of two locomotives and 100 bottom-dump cars would move coal to the plant; ash generated in the gasification of coal would be returned to the mine using this railroad system.

Water needed for gasification and other plant processes would total 7,900 acre-feet (ac-ft) per year, of which approximately 1,720 ac-ft would be supplied by moisture in the coal. The remainder (6,180 ac-ft) would be supplied from three sources: the existing LaPrele Reservoir, approximately 12 miles southwest of Douglas; a 1974 flood right appropriation from the North Platte River; and ground water. A

1.1 Summary of Proposed Action

Project Description and Location The coal gasification plant would be located approximately 15 miles northwest of Douglas, Wyoming. Commercially proven large scale gasification technologies would be used to produce a synthetic gas (syngas) at a heating value in the range of 100 to 120 Btu per cubic foot. An extra designed production and heating value, the plant would produce the equivalent of approximately 100 million Btu per day or 100 million Btu per year.

Coal for gasification would be supplied from the Rockville Mine, a proposed surface mine located approximately 40 miles north of the proposed plant site. In accordance with Wyoming law, the mine would supply 11 million tons of coal per year to the plant. Estimated coal resources at the Rockville Mine are in excess of 500 million tons of subbituminous coal. The coal would be mined in a truck and shovel operation.

Delivery of the coal to the gasification plant would be by a 40-mile electric railroad. The railroad and rolling stock would be owned by WYCOGAS. Each train consisting of two locomotives and 100 hopper cars would move coal to the plant; air generated in the gasification of coal would be returned to the mine using this railroad system.

Water needed for gasification and other plant processes would come from the North Platte River, of which approximately 1,700 acre-feet would be supplied by agreement in the coal. The remainder (1,100 acre-feet) would be supplied from other sources. The existing Laramie River, approximately 15 miles northwest of Douglas, a 1974 flood right appropriation from the North Platte River, and ground water. A

26,000 acre-foot storage reservoir would be constructed to store the floodwater from the North Platte River and the excess water from LaPrele Reservoir.

Delivery of the SPG to PEC and PG&E markets would be through the existing nationwide natural gas transmission system. To connect with the existing system, 162 miles of 24-inch-diameter pipeline would be constructed from the plant site south to a tie-in with the existing gas transmission network, just inside the Colorado border. The pipeline would be owned and operated by Panhandle Eastern Pipe Line Company (PEPL), a wholly owned subsidiary of PEC. Plant and pipeline design would allow for the possible comingling of natural gas from the Powder River Basin at the tailgate of the plant.

Destination of Product. Once the SPG reached the market areas of PEPL and PG&E, it would be distributed as part of their total system supply. PEPL's primary market area covers major portions of Michigan, Illinois, Indiana, Ohio, and Missouri. This area consumes approximately 25 percent of the total natural gas used in the contiguous 48 states. Of the total gas requirements in the market area, PEPL provides approximately 23 percent (1 trillion cubic feet in 1979) of the supply. PEPL transmission systems are the wholesale source of supply for 130 utility and municipal distribution systems in the region, which in turn supply about 2.7 million gas meters.

PG&E supplies both electric and gas service throughout most of northern and central California. The utility furnishes natural gas service to over 28 million residential and industrial customers in this area.

25,000 acre-foot storage reservoir would be constructed to store the floodwater from the North Platte River and the excess water from Little Blaine River.

Delivery of the 150 to 170 and 180 million acre-foot would be through the existing natural gas transmission system. To connect with the existing system, 125 miles of 36-inch-diameter pipeline would be constructed from the plant site south to a tie-in with the existing gas transmission network, just inside the Colorado border. The pipeline would be owned and operated by Transwestern Pipeline Corp. (TWP), a wholly owned subsidiary of TSC. TWP and pipeline design would allow for the possible combination of natural gas from the Powder River basin as the fuel gas at the plant.

Availability of Fuel Gas Since the 150 million acre-foot of TWP and TSC, it would be distributed as part of their total system supply. TWP's existing system serves major portions of Michigan, Indiana, Indiana, Ohio, and Missouri. This area consumes approximately 25 percent of the total natural gas used in the contiguous 48 states. Of the total gas requirements in the market area, TWP provides approximately 22 percent (1 billion cubic feet in 1975) of the supply. TWP transmission systems are the wholesale source of supply for 150 million and smaller distribution systems in the region, which is now supply about 2.7 million gas barrels.

1975 supplies both electric and gas service throughout most of northern and central California. The utility furnishes natural gas service to over 15 million residential and industrial customers in this area.

### 1.3 Project Background

Due to the declining natural gas supply base, PEPL began to explore alternative sources of gas supply in the late 1960s. Feasibility studies led to the conclusion that coal gasification, among other methods, would offer an acceptable alternative supply of gas. Thereafter the company, through its WyCoalGas Inc., subsidiary, assembled a project team, chose major contractors, and proceeded with project development, including process selection and design.

In the early 1970s, WyCoalGas determined that coal, land, and water resources were available for a coal gasification plant in Wyoming; see chapter 5 for a discussion of plant site alternatives. After conducting several studies of process and other unit design alternatives, a preliminary design was developed in 1974 for a 270-billion Btu SPG plant based on Wyoming coal, using Lurgi technology. A full environmental assessment was prepared and submitted to a federal interagency review committee, but because of the failure of federal loan guarantee legislation at that time, WyCoalGas requested that the report not be considered then.

In 1976 the company completed detailed process engineering, and the conceptual design for the plant was refined. The project was again delayed pending loan guarantee legislation.

A full program for the development of wastewater treatment practices for the proposed plant was completed in 1977. Methods of treating the phenolic water from the gasifier were developed, suggesting that SPG production could be achieved without discharge of water from the plant.

It became apparent in 1979 that because of possible procedural delays associated with the Toxic Substances Control Act (TSCA), marketing of the liquid hydrocarbon by-products from the Lurgi plant

1.3 Project Background

Due to the declining natural gas supply base, WYCO began to explore alternative sources of gas supply in the late 1960s. Feasibility studies led to the conclusion that coal gasification, among other methods, would offer an acceptable alternative supply of gas. Therefore, the company, through its WycolGas Inc., subsidiary, assembled a project team, chose major contractors, and proceeded with project development, including process selection and design.

In the early 1970s, WycolGas determined that coal, land, and water resources were available for a coal gasification plant in Wyoming. See Chapter 2 for a discussion of plant site alternatives. After conducting several studies of process and other site design alternatives, a preliminary design was developed in 1974 for a 210-million Btu per day plant based on WycolGas technology. A full environmental assessment was prepared and submitted to a Federal interagency review committee, but because of the failure of Federal loan guarantee legislation at that time, WycolGas requested that the report not be submitted then.

In 1975 the company completed detailed process engineering, and the conceptual design for the plant was revised. The project was again delayed pending loan guarantee legislation.

A full program for the development of wastewater treatment facilities for the proposed plant was completed in 1977. Methods of treating the process water from the gasifier were developed, suggesting that 210 production could be achieved without discharge of water from the plant.

It became apparent in 1979 that because of possible procedural delays associated with the Toxic Substances Control Act (TSCA), marketing of the liquid hydrocarbon by-products from the large plant

would be difficult. Therefore, WyCoalGas conducted feasibility studies which indicated that a Texaco gasifier could be added to the plant design to gasify internal streams into an additional 22 billion Btu of SPG. Saleable byproducts such as ammonia and sulfur would still be produced from such a plant.

The Department of Energy (DOE) has provided cost-sharing, in the form of Cooperative Agreements, as a means to expedite development of synthetic fuels projects. Such agreements from the DOE provide funds for permitting and design to bring a project to construction. On April 25, 1980, WyCoalGas submitted to DOE a Proposal for a Cooperative Agreement. This proposal was selected, and a Cooperative Agreement, designated No. DE-FC02-81RA50404, was consummated between WyCoalGas and DOE. By accepting the cooperative agreement with DOE (12.96 million dollars), WyCoalGas accelerated the project beyond the pace that could prudently be pursued with internally granted funds. If the project is constructed, WyCoalGas must pay back the \$12.96 million with interest; if the project is not constructed, the money provided under the cooperative agreement reverts to the form of a grant.

would be difficult. Therefore, WFO-12 has conducted feasibility studies which indicate that a feasible project could be added to the plant design in easily feasible manner for an additional 15 million per year. Substantive hydrologic data at amount and water would still be produced from such a plant.

The Department of Energy (DOE) has provided cost-sharing in the form of Cooperative Agreements, as a means to expedite development of hydroelectric projects. Such agreements from the DOE provide funds for planning and design to bring a project to construction. On April 15, 1980, WFO-12 submitted a DOE proposal for a Cooperative Agreement. This proposal was rejected, and a Cooperative Agreement, designated No. DE-F001-81-00000, was recommended between WFO-12 and DOE. By accepting the cooperative agreement with DOE (\$11.95 million dollars), WFO-12 advanced the project beyond the point that could previously be pursued with interest-free loan funds. If the project is constructed, WFO-12 must pay back the \$11.95 million with interest; if the project is not constructed, the money provided under the cooperative agreement reverts to the form of a grant.

## Chapter 2

## PURPOSE AND NEED

2.1 Purpose of the Project

The purpose of the proposed project is to provide a long-range gas supply for Panhandle Eastern Pipe Line Company and its customers, while reducing the nation's dependence on foreign oil and gas and the threat of disruption from potential interruptions in those supplies. The proposed project would produce 300 billion Btu of synthetic pipeline gas (SPG) per day and could displace more than 16 million barrels of oil per year, representing an annual reduction of almost \$575 million in payments for imported oil at current prices of approximately \$36 per barrel. Of equal importance, the addition of SPG to the nation's overall supply of natural gas assures continued efficient use of existing interstate gas transmission and local distribution systems, adding many years of useful service to consumer appliances, heating systems, and industry.

Panhandle Eastern's primary service area covers major portions of Michigan, Illinois, Indiana, Ohio, and Missouri. Approximately 25 percent of the total natural gas used in the contiguous United States is consumed in this area, and Panhandle provides approximately 23 percent of the area gas requirements (nearly one trillion cubic feet in 1979). Panhandle Eastern is the wholesale source of gas for 130 utilities and municipalities in the service area. These distributors supply approximately 2.7 million gas meters.

It has always been Panhandle Eastern's policy to maintain an aggressive acquisition program for domestic natural gas reserves. However, in the late 1960s, Panhandle was withdrawing gas from reserve to meet increasing market requirements by customers without being able to fully replace these supplies. For this reason, Panhandle began exploring alternative sources.

Chapter 2

INTRODUCTION AND SCOPE

2.1 Purpose of the Project

The purpose of the proposed project is to provide a long-range gas supply for the Pacific Northwest Pipe Line Company and its customers, while reducing the nation's dependence on foreign oil and gas and the threat of disruption from potential international interruptions in those supplies. The proposed project would produce 300 million feet of synthetic gas from gas (1975) per day and could displace more than 10 million barrels of oil per year, representing an annual reduction of about 300,000 barrels from the proposed gas pipeline. The addition of 300 to the nation's overall supply of natural gas assets contained within the existing interstate gas transmission and local distribution systems, adding many years of useful service to consumer appliances, heating systems, and industry.

Pacific Northwest's primary service areas cover major portions of Michigan, Illinois, Indiana, Ohio, and Missouri. Approximately 25 percent of the total natural gas used in the contiguous United States is consumed in this area, and Pacific Northwest provides approximately 25 percent of the area gas requirements (nearly one trillion cubic feet in 1975). Pacific Northwest is the wholesale source of gas for 130 utilities and municipalities in the service area. These distribution supply approximately 2.5 million gas meters.

It has always been Pacific Northwest's policy to maintain an aggressive exploration program for domestic natural gas reserves. However, in the late 1960s, Pacific Northwest was withdrawing gas from reserves to meet increasing market requirements by customers without being able to fully replace those supplies. For this reason, Pacific Northwest began exploring alternative sources.

Panhandle Eastern investigated the feasibility of constructing a plant to gasify liquid hydrocarbons. Commercial technology is available for the production of SPG from naptha and other light hydrocarbons; however, this alternative did not appear to represent a wise use of a resource that is also in short supply.

Panhandle identified coal gasification as a viable alternative for supplementing supplies to their distribution system. The United States contains abundant economical reserves of coal, and coal gasification technology has been proven on a commercial scale in Europe and South Africa.

Panhandle Eastern has recently acquired, and is continuing to seek, domestic and foreign sources of natural gas. In 1974, Panhandle completed a gas-supply system from the Wattenberg Field near Denver, Colorado. Beginning in 1970, the company has invested in gas exploration and production in the offshore Louisiana area. Participation in various partnerships has given Panhandle access to potential gas reserves from these offshore fields. Panhandle Eastern is actively pursuing the development of the proposed natural gas transmission system intended to transport Alaskan north slope gas via pipeline to the central United States. In 1973, the company concluded arrangements with Sonatrach, the state petroleum company of Algeria, to import as liquefied natural gas (LNG) the equivalent of 3.3 trillion cubic feet of gas. A terminal has recently been completed in Louisiana to receive this LNG.

In recent years, the effects of conservation by all classes of gas consumers, the advent of more efficient appliances and heating equipment, fuel switching by industrial users, and the depressed economy have reduced the overall demand for gas in Panhandle's service area. Concurrently, there has been an increase in the volumes of flowing gas available for transmission, primarily as a result of

Technological Eastern investigated the feasibility of constructing a plant to jointly liquid hydrocarbons. Commercial technology is available for the production of 200,000 tons annually and other 1,000 hydrocarbons; however, this alternative did not appear to represent a wise use of a resource that is also in short supply.

Technological identified coal gasification as a viable alternative for supplementing supplies to their distribution system. The United States contains abundant economic reserves of coal, and coal gasification technology has been proven on a commercial scale in Europe and South Africa.

Technological Eastern has recently acquired, and is continuing to seek, domestic and foreign sources of natural gas. In 1974, Technological completed a gas-transport system from the Vashon Island gas burner, Colorado. Beginning in 1975, the company has invested in gas exploration and production in the offshore Louisiana area. Participation in various partnerships has given Technological access to potential gas reserves from these offshore fields. Technological Eastern is actively pursuing the development of the proposed natural gas transmission system intended to transport Alaskan north slope gas via pipeline to the central United States. In 1977, the company concluded arrangements with Conoco, the state petroleum company of Alaska, to import as liquefied natural gas (LNG) the equivalent of 2.5 million cubic feet of gas. A terminal has recently been completed in Louisiana to receive this LNG.

In recent years, the effects of conservation by all classes of gas consumers, the advent of more efficient appliances and heating equipment, fuel switching by industrial users, and the depressed economy have reduced the overall demand for gas in Technological's service area. Consequently, there has been an increase in the volume of flowing gas available for transmission, primarily as a result of

high production rates from newly developed gas fields. The combined effect of these conditions has been the creation of a surplus of gas in Panhandle's system. However, this surplus is not expected to extend beyond the next few years because current production has not been completely replaced on a national basis. Between 1975 and 1979, only 56 percent of the volume of gas produced in the United States was replaced (Robert W. Reed, Panhandle Eastern Corporation, personal communication, 1981). These circumstances reinforce Panhandle's policy of aggressive acquisition of conventional gas reserves and necessitates development of supplementary sources, such as coal gasification.

In 1980, Panhandle Eastern forecast the residential, commercial, and industrial demand for gas in its primary service area through 1995. Competitive fuel prices, conservation efforts, fuel-burning flexibility, and changing levels of economic activity were key elements of the analysis.

This study forecast demand for gas in the primary service area to increase gradually through the mid-1980s, due primarily to a temporary increase in gas availability and its competitive price position. However, in the late 1980s, total gas demand is expected to begin to decline slightly as conservation offsets new load growth. Residential demand is expected to decline throughout most of the forecast period as a result of significant increases in residential conservation, although gas is projected to retain a relatively high market share. On the other hand, commercial demands for gas are expected to increase throughout the forecast period. In the industrial sector, the effects of higher oil prices and improved gas supplies are evident in the increased demand for gas at the beginning of the 1980s. Industrial gas demand after 1985 is expected to decline somewhat due to a reduction in the rate of growth in total energy demand for the

high production rates from newly developed gas fields. The combined effect of these conditions has been the creation of a surplus of gas in Pennsylvania's basins. However, this surplus is not expected to extend beyond the next few years because current production has not been completely replaced on a national basis. Between 1972 and 1978, only 36 percent of the volume of gas produced in the United States was replaced (Robert W. Reed, Pennsylvania Eastern Corporation, personal communication, 1981). These circumstances reflect the Pennsylvania's policy of restrictive regulation of conventional gas reserves and accelerated development of supplementary sources, such as coal gasification.

In 1980, Pennsylvania Eastern forecast the residential, commercial, and industrial demand for gas in the primary service area through 1990. Competitive fuel prices, conservation efforts, fuel-switching flexibility, and changing levels of economic activity were key elements of the analysis.

This study forecast demand for gas in the primary service area to increase gradually through the mid-1990s, due primarily to a temporary increase in gas availability and its competitive price position. However, in the late 1990s, when gas demand is expected to begin its decline slightly as conservation efforts slow down growth. Residential demand is expected to decline throughout most of the forecast period as a result of significant increases in residential conservation, although gas is projected to retain a relatively high market share. On the other hand, commercial demands for gas are expected to increase throughout the forecast period. In the industrial sector, the effects of higher oil prices and improved gas supplies are evident in the increased demand for gas at the beginning of the 1990s. Residential gas demand after 1995 is expected to decline somewhat due to a reduction in the rate of growth in total energy demand for the

industrial sector and some loss in market share for gas after deregulation.

While the demand for gas in Panhandle's service area will decline over the forecast period, supplies will decrease at a greater rate. Table 2.1-1 compares forecasted supplies of gas to Panhandle from all sources (i.e., domestic reserves, LNG, and the proposed coal gasification project) with demand through 1995. Shortfalls in gas supply are expected to begin by at least 1985 unless further sources are obtained. As indicated in Table 2.1-1, the proposed project would play an important role in decreasing Panhandle's project system deficiencies.

## 2.2 Need for Federal Action

Under Title V of the Federal Land Policy and Management Act of 1976 (FLPMA) (43 U.S.C. 1971), the U.S. Bureau of Land Management is authorized to issue grants of right-of-way for industrial facilities that cross lands under its jurisdiction. WyCoalGas has submitted applications for right-of-way grants on 5.99 acres of federal land to be inundated by Combs Reservoir (Serial Number W47428), and 75.052 acres (8,173.120 feet at 400-foot-wide right-of-way) of federal land to be crossed by the proposed electric railroad.

In accordance with the National Environmental Policy Act of 1969, it is the responsibility of federal agencies to prepare an environmental impact statement (EIS) for a proposed major action which may cause significant environmental impacts. The BLM has determined that issuance of the right-of-way grants for the proposed project would be a major action requiring an EIS.



TABLE 2.1-1

SUPPLY/DEMAND FORECASTS FOR GAS IN THE PANHANDLE EASTERN  
SYSTEM (billion cubic feet)

	Actual Consumption (1978)	Forecast		
		1985	1990	1995
Supplies from all sources except coal gasification	2,477	2,527	2,414	2,266
Coal gasification	0	0	102	102
Total Demand	2,477	2,707	2,679	2,634
Expected supply short- fall in service area	0	0	0	0

Source: Robert W. Reed, Panhandle Eastern Corporation, personal communication, 1981.

TABLE 2-1-1  
SUPPLY/DEMAND FORECAST FOR THE TANKS AND BATTERIES  
SYSTEM (in thousands of tons)

	Forecast			Actual Consumption (1962)
	1962	1963	1964	
Supplies from all sources except gasification	2,288	2,412	2,537	2,407
Coal gasification	101	102	0	0
Total demand	2,389	2,514	2,537	2,407
Expected supply short- fall in various years	0	0	0	0

Source: Robert F. Good, Chemicals Research Corporation, personal  
communication, 1971.

## Chapter 3

### PROPOSED ACTION

#### 3.1 GENERAL DESCRIPTION

##### Components

The proposed project would be located in Campbell, Converse, Platte, and Laramie counties, Wyoming, and Weld County, Colorado (see Figure 1.1-1). Its major components would be a gasification plant, a coal mine, a coal transportation system, a water supply system, and a product pipeline connecting the projects to the existing nationwide natural gas transmission system. Figure 3.1-1 is a schematic representation of the entire complex. Each component is described in detail in following sections.

##### Acreage Requirements and Land Status

Approximately 11,200 acres would be affected during construction of the proposed project. Project operation would require approximately 8,100 acres. Table 3.1-1 is a breakdown of land requirements by project component. Table 3.1-2 shows land ownership by component.

#### 3.2 SCHEDULE AND WORKFORCE

##### Schedule

Construction of the project would begin in 1982, with operation commencing in 1986. The plant would be constructed in two stages. Construction of the first stage would take place from 1983 to 1986; construction of the second stage would occur from 1986 to 1988. Figure 3.2-1 shows the proposed schedule for construction of the major project components.



Table 3.1-1

ADVANCE ENVIRONMENTAL, PHYSICAL PROJECT

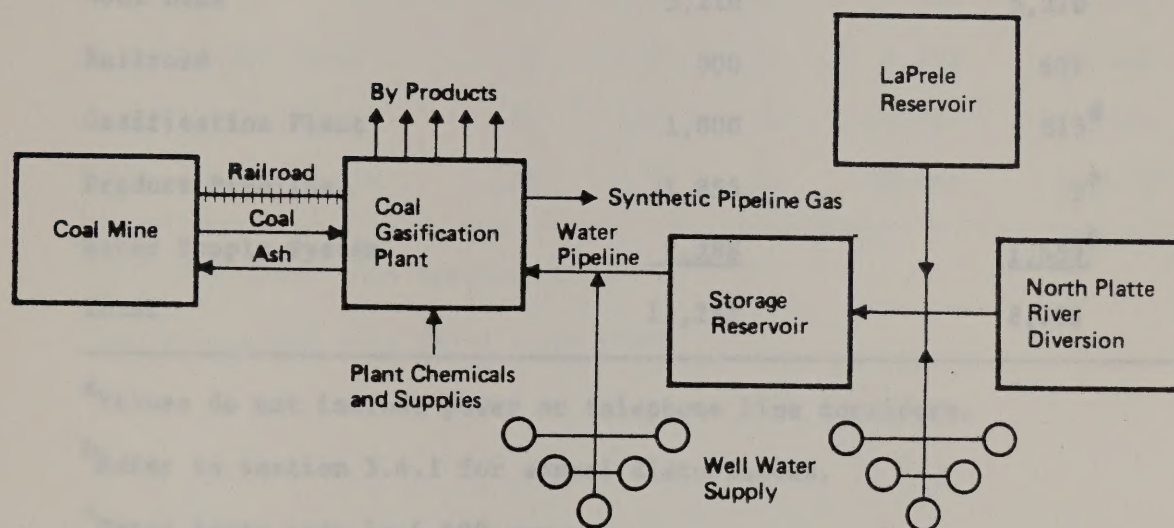


Figure 3.1-1  
COAL GASIFICATION COMPLEX—PROPOSED MAJOR FACILITIES

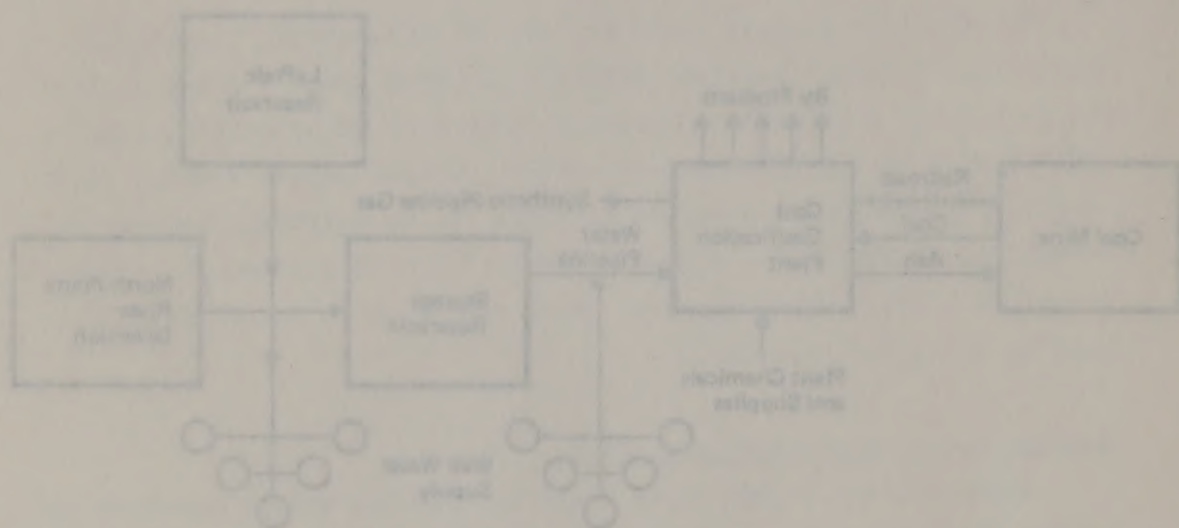


Figure 3-1-1  
COAL GASIFICATION COMPLEX—PROPOSED MAJOR FACILITIES

Table 3.1-1

ACREAGE REQUIREMENTS, WYCOALGAS PROJECT<sup>a</sup>

Component	Disturbed Acreage, Construction	Occupied Acreage, Operation
Coal Mine <sup>b</sup>	5,210 <sup>c</sup>	5,210 <sup>c</sup>
Railroad	900	607
Gasification Plant	1,000	815 <sup>d</sup>
Product Pipeline	1,855	5 <sup>e</sup>
Water Supply System	<u>2,288</u>	<u>1,459<sup>f</sup></u>
Total	11,253	8,096

<sup>a</sup>Values do not include power or telephone line corridors.

<sup>b</sup>Refer to section 3.4.1 for annual disturbances.

<sup>c</sup>Total lease area is 6,600 acres.

<sup>d</sup>Total lease area is 3,697 acres.

<sup>e</sup>Operational surface use limited to 9 valve stations, each occupying 1/2 acre.

<sup>f</sup>Total lease area is 43,169 acres.

Table 1-1-1  
ACRES REQUIRING WYOMING PROJECT

Component	Disturbed Acres, Construction	Conserved Acres, Operation
Coal Mine <sup>a</sup>	2,210 <sup>c</sup>	2,210 <sup>c</sup>
Railroad	400	400
Gasification Plant	1,000	813 <sup>d</sup>
Process Pipeline	1,400	2 <sup>e</sup>
Water Supply System	2,200	1,400 <sup>f</sup>
Total	11,210	5,020

<sup>a</sup>Values do not include power or telephone line corridors.

<sup>b</sup>Water to be used 1.41 for annual drawdown.

<sup>c</sup>Total lease area is 6,600 acres.

<sup>d</sup>Total lease area is 5,600 acres.

<sup>e</sup>Operational surface use limited to 9 valve stations, each occupying 1/2 acre.

<sup>f</sup>Total lease area is 51,167 acres.

Table 3.1-2

## LAND OWNERSHIP, WYCOALGAS PROJECT

Component	Acreage				Total
	Federal	State	County	Private	
Coal Mine	3,360	640	0	2,600	6,600
Railroad	132	50	3	422	607
Gasification Plant	0	0	0	3,682	3,697 <sup>a</sup>
Product Pipeline	30	121	0	1,703	1,855
Water Supply System	80	0	0	43,089	43,169 <sup>b</sup>

<sup>a</sup>Includes total site ownership.

<sup>b</sup>Includes total well field lease area.

Table 3-1-1  
LAND OWNERSHIP, WYOMING PROJECT

Component	Acres			
	Federal	State	County	Private
Coal Mine	3,700	450	0	1,800
Railroad	133	50	0	433
Reclamation Plant	0	0	0	3,800
Power Plant	30	121	0	1,700
Water Supply System	80	0	0	43,000

<sup>a</sup> Includes total site ownership.

<sup>b</sup> Includes total with third party.

Figure  
3.2-1

CONSTRUCTION SCHEDULE, WYCOALGAS PROJECT

	Year							
	1982	1983	1984	1985	1986	1987	1988	1989
Mine	—	—	—	—	—	—	—	—
Railroad	—	—	—	—	—	—	—	—
Plant, 1st Phase	—	—	—	—	—	—	—	—
Plant, 2nd Phase	—	—	—	—	—	—	—	—
Water System	—	—	—	—	—	—	—	—
Product Pipeline	—	—	—	—	—	—	—	—

The proposed coal gasification plant would be located in Converse County, Montana, 16 miles northwest of Douglas. Figure 3.2-1. At completion the plant would produce a nominal 700 million standard cubic feet per day of high-Btu synthetic pipeline gas (HSPG) from coal, using Lurgi and Winkler gasification technologies. Heating value of this gas would be 950 to 1000 Btu/SCF.

The plant operation would include offices, shops, medical facilities, fire protection, water system, sewage, roads, and other support systems. Electric power for plant operations would be generated on-site using coal-fired boilers. Plant layout is shown in Figures 3.2-2 and 3.2-3. Coal and solid waste storage, raw water storage, process units, utility plant, and general facilities would require approximately 615 acres. Under agreements with the landowners, any land not used for facilities within the 3,487-acre lease area would be leased back for grazing purposes. Access to the plant would be via State Highway 59, approximately 1 1/2 miles of County Road 35 near the plant.

Page 3-5-1

CONSTRUCTION SCHEDULE, WYOMING PROJECT

	Year						
	1981	1982	1983	1984	1985	1986	1987
Water System							
Process Pipelines							
Plant, 1st Phase							
Plant, 2nd Phase							
Refinery							
Other							

### Workforce

Construction and operation of the proposed project would involve a work force that would reach a peak of 3,200 in 1986. Construction personnel would come primarily from outside the area, although the workforce would draw to a limited extent from workers completing other projects in the area. It is anticipated that perhaps 10 percent of the work force would be recruited from permanent residents in the area. Table 3.2-1 projects the personnel required for each of the major components of the project for both the construction phase and the operational phase; Table 3.2-2 presents estimated monthly payrolls.

## 3.3 COAL GASIFICATION PLANT

### GENERAL DESCRIPTION

The proposed coal gasification plant would be located in Converse County, Wyoming, 16 miles northeast of Douglas; see Figure 3.3-1. At completion the plant would produce a nominal 300 million standard cubic feet per day of high-Btu synthetic pipeline gas (SPG) from coal, using Lurgi and Texaco gasification technologies. Heating value of this gas would be 950 to 960 Btu/SCF.

The plant operation would include offices, shops, medical facilities, fire protection, water system, sewers, roads, and other support systems. Electric power for plant operations would be generated on-site using coal-fired boilers. Plant layout is shown in Figures 3.3-2 and 3.3-3. Coal and solid waste storage, raw water storage, process units, utility plants, and general facilities would require approximately 815 acres. Under agreements with the landowners, any land not used for facilities within the 3,697-acre lease area would be leased back for grazing purposes. Access to the plant would be via State Highway 59, approximately 1 1/2 miles of County Road 55 near the plant

Notes

Construction and operation of the proposed project would involve a work force that would reach a peak of 1,200 in 1987. Construction personnel would come primarily from outside the area, although the workforce would draw to a limited extent from workers completing other projects in the area. It is anticipated that perhaps 10 percent of the work force would be recruited from permanent residents in the area. Table 3-1-1 presents the personnel required for each of the construction phases of the project for both the construction phase and the operational phase; Table 3-2-1 presents estimated monthly payrolls.

3.3 COAL GASIFICATION PLANT

GENERAL DESCRIPTION

The proposed coal gasification plant would be located in County, Wyoming, 15 miles southeast of Douglas; see Figure 3-3-1. At completion the plant would produce a nominal 300 million standard cubic feet per day of high-Btu synthetic pipeline gas (SPG) from coal, using Lurgi and Texaco gasification technologies. Heating value of this gas would be 950 to 960 Btu/scf.

The plant operation would include offices, shops, medical facilities, fire protection, water system, sewer, roads, and other support systems. Electric power for plant operations would be generated on-site using coal-fired boilers. Plant layout is shown in Figures 3-3-2 and 3-3-3. Coal and related waste storage, raw water storage, process water, utility plants, and general facilities would require approximately 500 acres. Other agreements with the landowners, any land not used for facilities within the 5,000-acre lease area would be leased back for grazing purposes. Access to the plant would be via State Highway 19, approximately 1 1/2 miles of County Road 55 near the plant.

Table 3.2-1

APPROXIMATE AVERAGE WYCOALGAS PROJECT WORKFORCE BY YEAR<sup>a</sup>

	1982	1983	1984	1985	1986	1987	1988	1989
Surface Mine								
Construction	137	199	--	--	--	--	--	--
Operation	--	--	105	140	184	239	251	255
Railroad								
Construction <sup>b</sup>	--	80-155 <sup>b</sup>	80-155 <sup>b</sup>	--	--	--	--	--
Operation	--	--	--	40	40	40	40	40
Gasification Plant								
Construction <sup>c</sup>	--	495	1,861	3,044	2,479	2,578	583	--
Operation	--	12	25	98	481	786	936	1,045
Product Pipeline								
Construction <sup>d</sup>	--	--	--	--	123 <sup>d</sup>	--	--	--
Operation	--	--	--	--	2	2	2	2
Water Supply System								
Construction <sup>e</sup>	--	210	248	56	--	--	--	--
Operation	--	--	--	--	16	16	16	16
Total								
Construction <sup>f</sup>	137	984-1,059	2,189-2,264	3,100	2,602	2,578	583	--
Operation	--	12	130	278	723	1,081	1,205	1,358

<sup>a</sup> Assumes schedule in Figure 3.2-1.<sup>b</sup> Varies seasonally.<sup>c</sup> Peak plant construction workforce of \_\_\_\_\_.<sup>d</sup> Peak pipeline construction workforce of 245, duration 6 months.<sup>e</sup> Peak water system construction work force of 450.<sup>f</sup> Peak overall construction workforce of \_\_\_\_\_.



Table 3.2-2

APPROXIMATE AVERAGE MONTHLY PAYROLLS, WYCOALGAS PROJECT (Thousands of 1981 dollars)<sup>a</sup>

	1982	1983	1984	1985	1986	1987	1988	1989
Surface Mine								
Construction	725	850	--	--	--	--	--	--
Operation	--	--	245	300	400	552	552	552 <sup>b</sup>
Plant and Facilities <sup>c</sup>								
Construction	--	2,346	7,019	10,318	8,251	8,581	1,299	--
Operation	--	--	--	--	--	--	--	3,300
Product Pipelinent								
Construction	--	--	--	--	260	--	--	--
Operation	--	--	--	--	10	10	10	10
Total								

<sup>a</sup>Based on schedule in Figure 3.2-1.<sup>b</sup>Expected to remain constant through 1995, then gradually increase to 1,060 in peak year (expected no sooner than 2,009).<sup>c</sup>Includes water system and railroad.



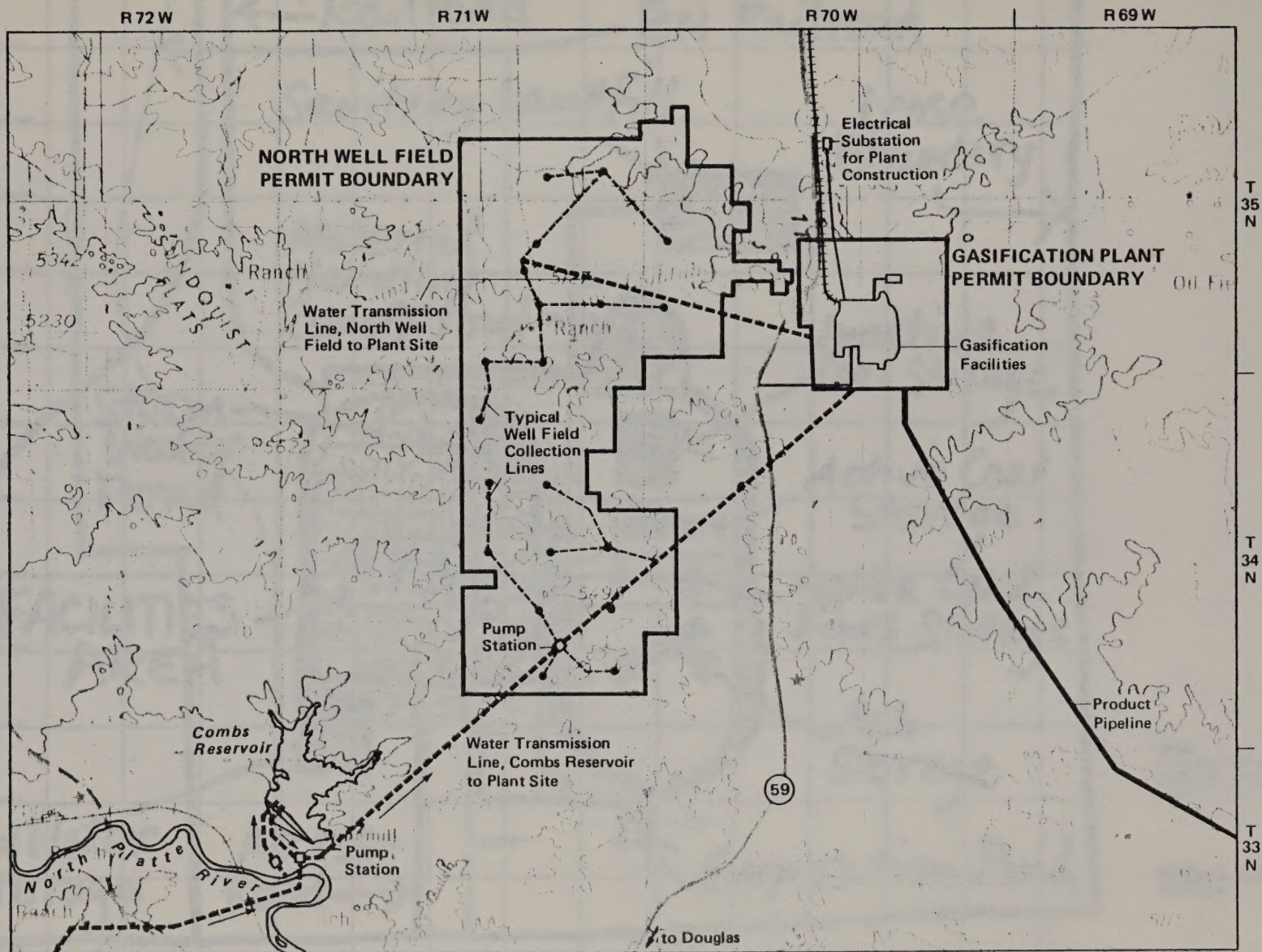
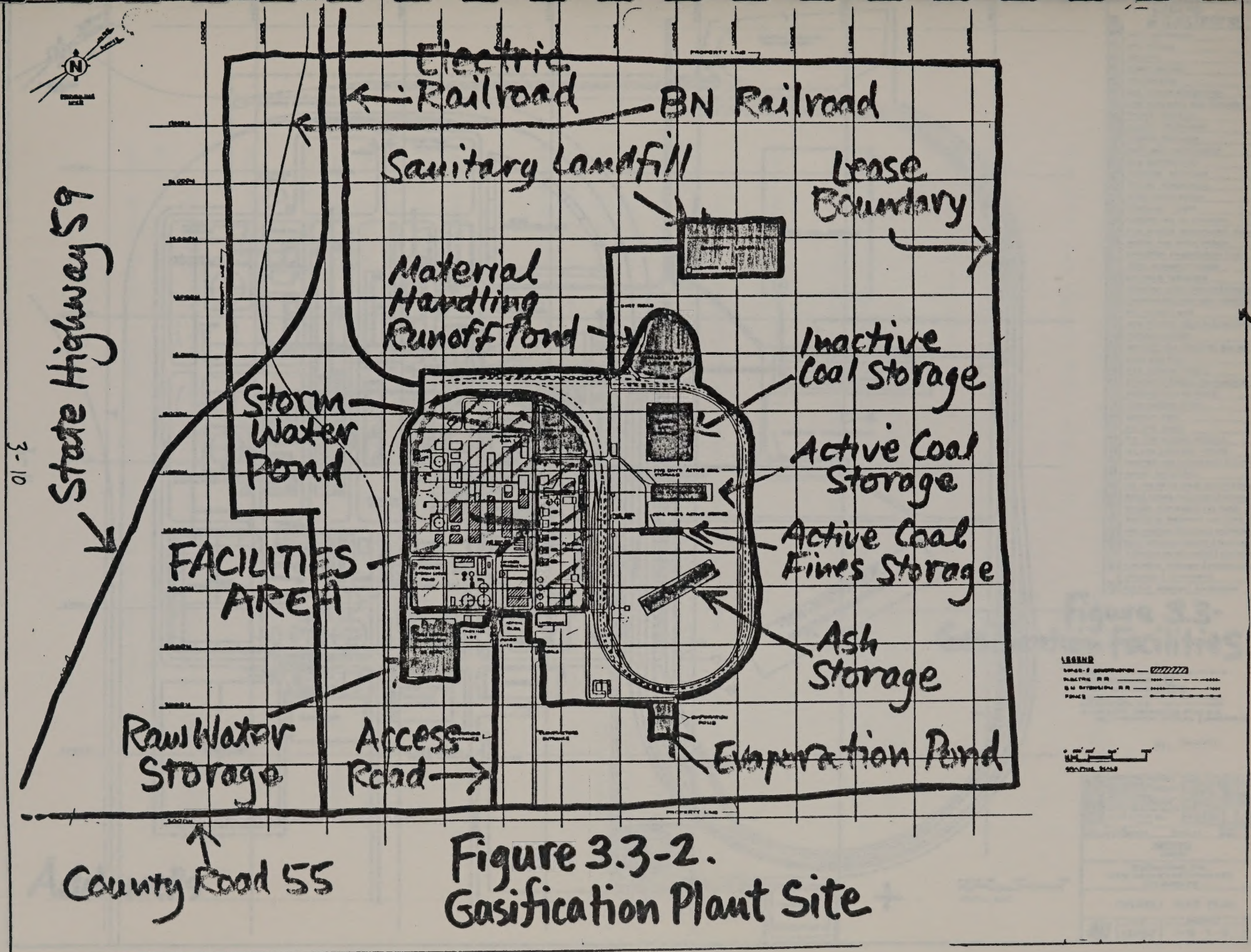


Figure 3.3-1  
GASIFICATION PLANT LOCATION

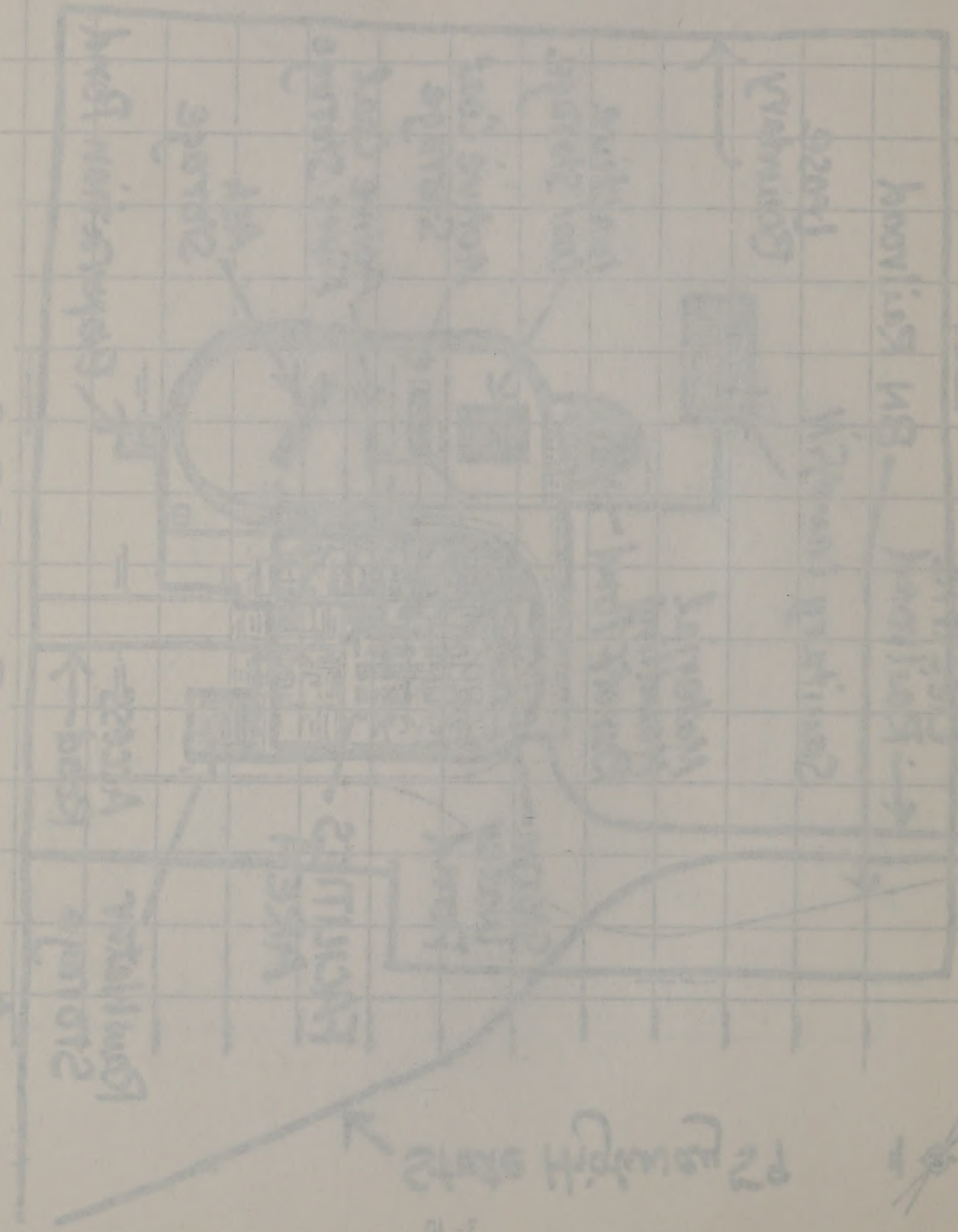




1

P2 power off state

2-10

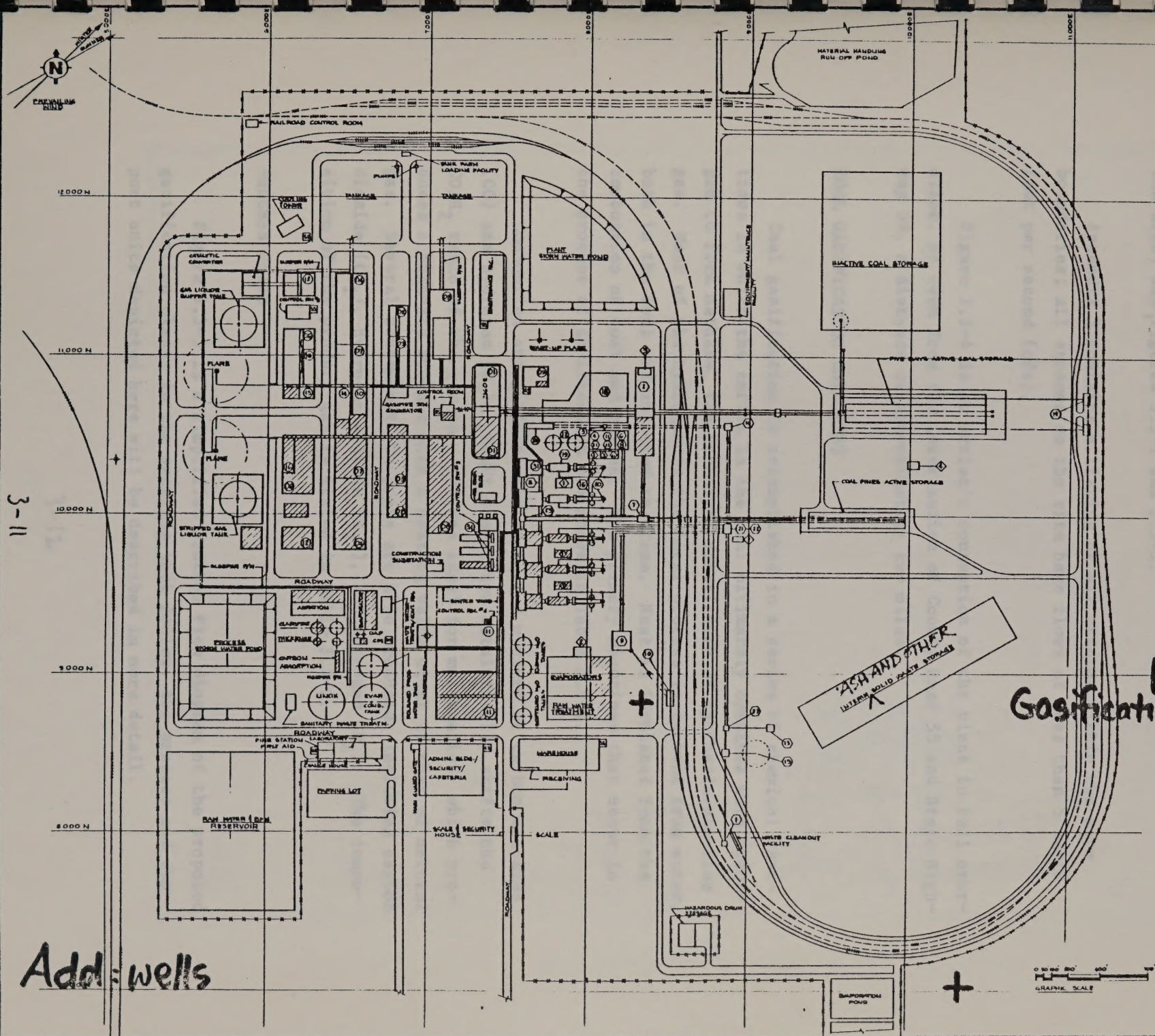


С.Е.Е. группа  
212 группа

22 группа

3-11

Add: wells



# LEGEND GASIFIER

- (1) SHIFT CONVERSION
- (2) GAS COOLING
- (3) RECTISOL
- (4) PHENOL SOLVING
- (5) METHANATION
- (6) GAS LIQUOR SEPARATION
- (7) LOW PRESSURE GAS RECOVERY
- (8) TENSAC GASIFIER
- (9) OXYGEN PRODUCTION
- (10) SULFUR RECOVERY
- (11) FINAL GAS COMPRESSION
- (12) GAS DEHYDRATION
- (13) AMMONIA RECOVERY
- (14) POWER GENERATION
- (15) WASTE LOADOUT FACILITY
- (16) SCREENING TOWER
- (17) F.E.D./RY ASH MIX CONVERSION
- (18) F.E.D. SLUDGE PREPARATION AREA
- (19) BOTTOM ASH PIPING TRENCH
- (20) LIMESTONE PREPARATION AREA
- (21) FINES TRANSFER TOWER
- (22) LIMESTONE SURGE BIN
- (23) LIMESTONE ACTIVE STORAGE / RECLAIM
- (24) LIMESTONE RECEIVING TRACK HOPPER FAC
- (25) FLY ASH PRED. DASH
- (26) COAL RAILCAR UNLOADING FACILITY
- (27) RECLAIM HOPPER
- (28) GASIFIER ASH TRANSFER TOWER
- (29) LOAD OUT PILE
- (30) F.E.D. MODULES (TYP)
- (31) GASIFIER / BOTTOM ASH DUCKELER
- (32) EMERGENCY ASH POND
- (33) PRECIPITATOR (TYP)
- (34) CHIMNEY (TYP)
- (35) FLY ASH WILDS
- (36) FLY ASH BLOWER BUILDING
- (37) FLY ASH LOAD OUT HOPPER
- (38) GASIFIER ASH DEWATERING FACILITY
- (39) BOILER SURGE BIN
- (40) FLY ASH TRUCK LOAD OUT STATION
- (41) SOLID WASTE STACK OUT / RECLAIM INC.
- (42) BOILER SWITCHGEAR (E) FEED
- (43) FASH / SPIN TREATMENT DASH / CRUT RM
- (44) ASH HANDLING / DISPOSAL SWITCHGEAR
- (45) COAL UNLOADING CONTROL / SWITCHGEAR
- (46) SCREENING TOWER CONTROL / SWITCHGEAR
- (47) LIMESTONE RECEIVING / PREPARATION
- (48) CONTROL / SWITCHGEAR
- (49) FLY ASH DISPOSAL SWITCHGEAR

Figure 3.3-  
Gasification Facilities

FENCE  
ELECTRICAL SUBSTATION  
STAGE - 8 CONSTRUCTION  
ELECTRIC RR  
BAY EXTENSION R.R.  
\* INCLUDES PRECIPITATOR PLUS GAS  
DEWATERATION CONTROL & SWITCHGEAR

NOT ORIGINAL

REVISED FOR PROJECT	BY	DATE	REVISED FOR PROJECT	BY	DATE
ISSUED FOR PROJECT	PL	12/1/60	ISSUED FOR PROJECT	PL	12/1/60
ISSUED FOR REVIEW	PL	12/1/60	ISSUED FOR REVIEW	PL	12/1/60
ISSUED FOR CONSTRUCTION	PL	12/1/60	ISSUED FOR CONSTRUCTION	PL	12/1/60
ISSUED FOR CONSTRUCTION	PL	12/1/60	ISSUED FOR CONSTRUCTION	PL	12/1/60

BECHTEL  
HEATON

WyComGas, Inc.  
COAL GASIFICATION PROJECT  
300 MMBCPD

OVERALL PLOT PLAN

REV. NO.	REVISION	DATE
13650	50E-A-2	1

0 100 200 300 400 500  
GRAPHIC SCALE



site's southern boundary, and a private road to be constructed within the site; see Figures 3.3-1 and 3.3-2.

Appendix 2 contains a listing of all streams within the site boundaries; all streams on the site have flows of less than 5 cubic feet per second (cfs).

Figure 3.3-4 is an artist's conception of the plant in full operation, as seen from the intersection of County Road 55 and State Highway 59, a distance of approximately two miles.

#### COAL GASIFICATION CHEMISTRY

Coal gasification is accomplished in a series of chemical reactions in which the carbon in the coal ultimately combines with hydrogen to form methane, the principal constituent of synthetic pipeline gas. Most of the hydrogen in the Lurgi process is derived from water, both in the coal and injected as steam. Heat is furnished from the combustion of coal and oxygen. The primary reactions that occur in the process of gasification are shown in Table 3.3-1.

Combustion and gasification produce a mixture of carbon monoxide (CO) and hydrogen ( $H_2$ ). Shift conversion catalytically shifts the CO/ $H_2$  ratio of the gas to a mixture ideal for methanation, which produces a high-Btu product with a heating value equal to that of natural gas. Several noncombustible gases are also produced, including carbon dioxide ( $CO_2$ ), hydrogen sulfide ( $H_2S$ ), and nitrogen ( $N_2$ ). The composition of the product gas is listed in Table 3.3-2.

#### PROCESS UNITS

Figure 3.3-5 is a simplified process flow diagram of the proposed gasification plant; in the sections that follow, the process and support units depicted here will be described in more detail.

the site: see Figures 3.3-1 and 3.3-2.

Appendix 1 contains a listing of all streams within the site boundaries; all streams on the site have flows of less than 5 cubic feet per second (cfs).

Figure 3.3-4 is an aerial photograph of the plant in full operation, as seen from the intersection of County Road 55 and State Highway 59, a distance of approximately two miles.

### COAL GASIFICATION OVERVIEW

Coal gasification is accomplished in a series of chemical reactions in which the carbon in the coal ultimately combines with hydrogen to form methane. The principal reactants of gasification are coal, steam, and oxygen. The hydrogen for the large process is derived from water, both in the feed and injected as steam. Heat is furnished from the combustion of coal and oxygen. The primary reactions that occur in the process of gasification are shown in Table 3.3-1.

Gasification and gasification produce a mixture of carbon monoxide (CO) and hydrogen (H<sub>2</sub>). While conversion catalytically shifts the CO/H<sub>2</sub> ratio of the gas to a mixture ideal for methanation, which produces a high-Btu product with a heating value equal to that of natural gas. Several noncombustible gases are also produced, including carbon dioxide (CO<sub>2</sub>), hydrogen sulfide (H<sub>2</sub>S), and nitrogen (N<sub>2</sub>). The composition of the product gas is listed in Table 3.3-2.

### PROCESS UNIT

Figure 3.3-3 is a simplified process flow diagram of the proposed gasification plant; in the sections that follow, the process and support units depicted here will be described in more detail.

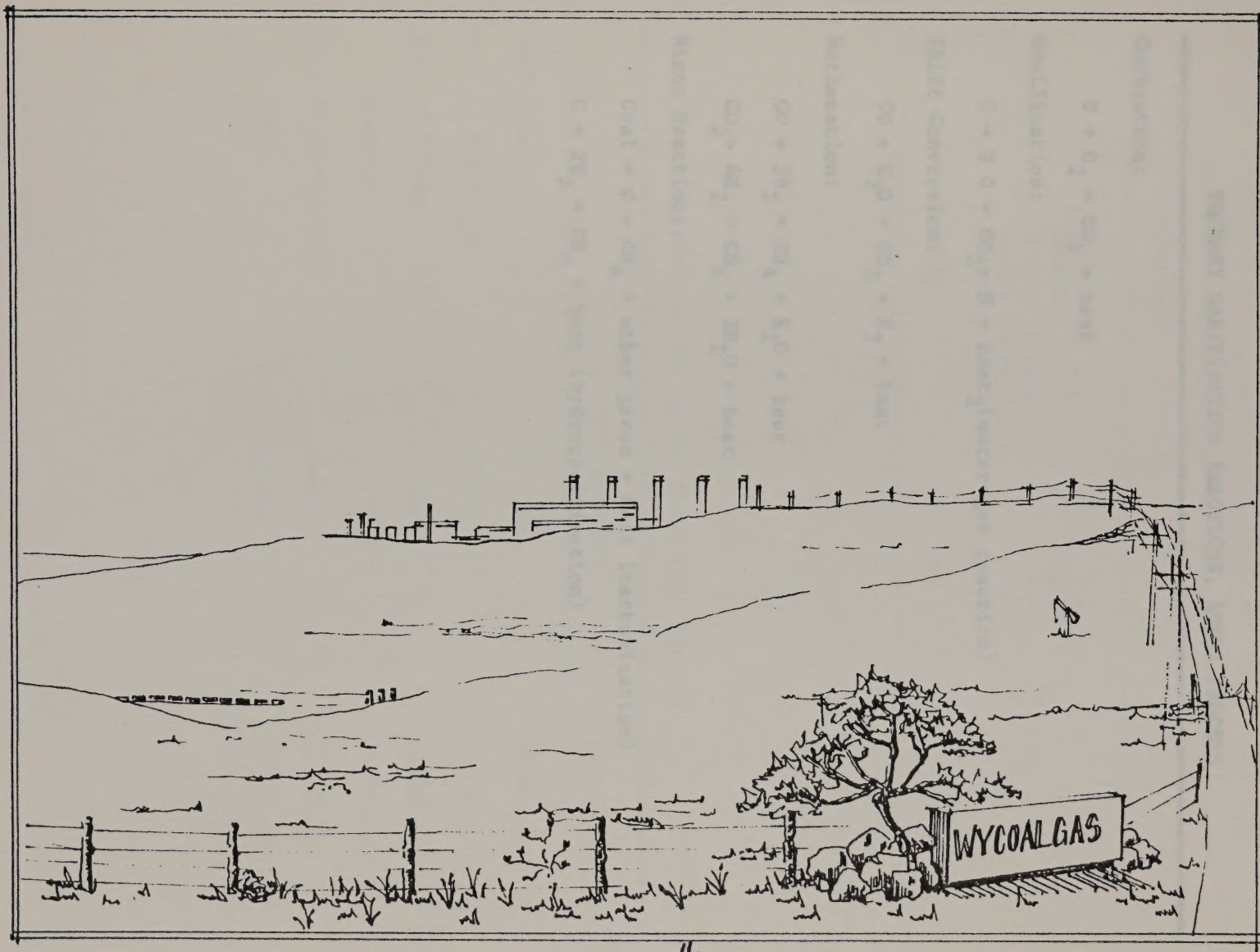


Figure 3.3-4  
ARTIST'S CONCEPT OF PLANT

WILLIS' CONCEPT ON BEHAVIOR  
OF THE SUBJECT

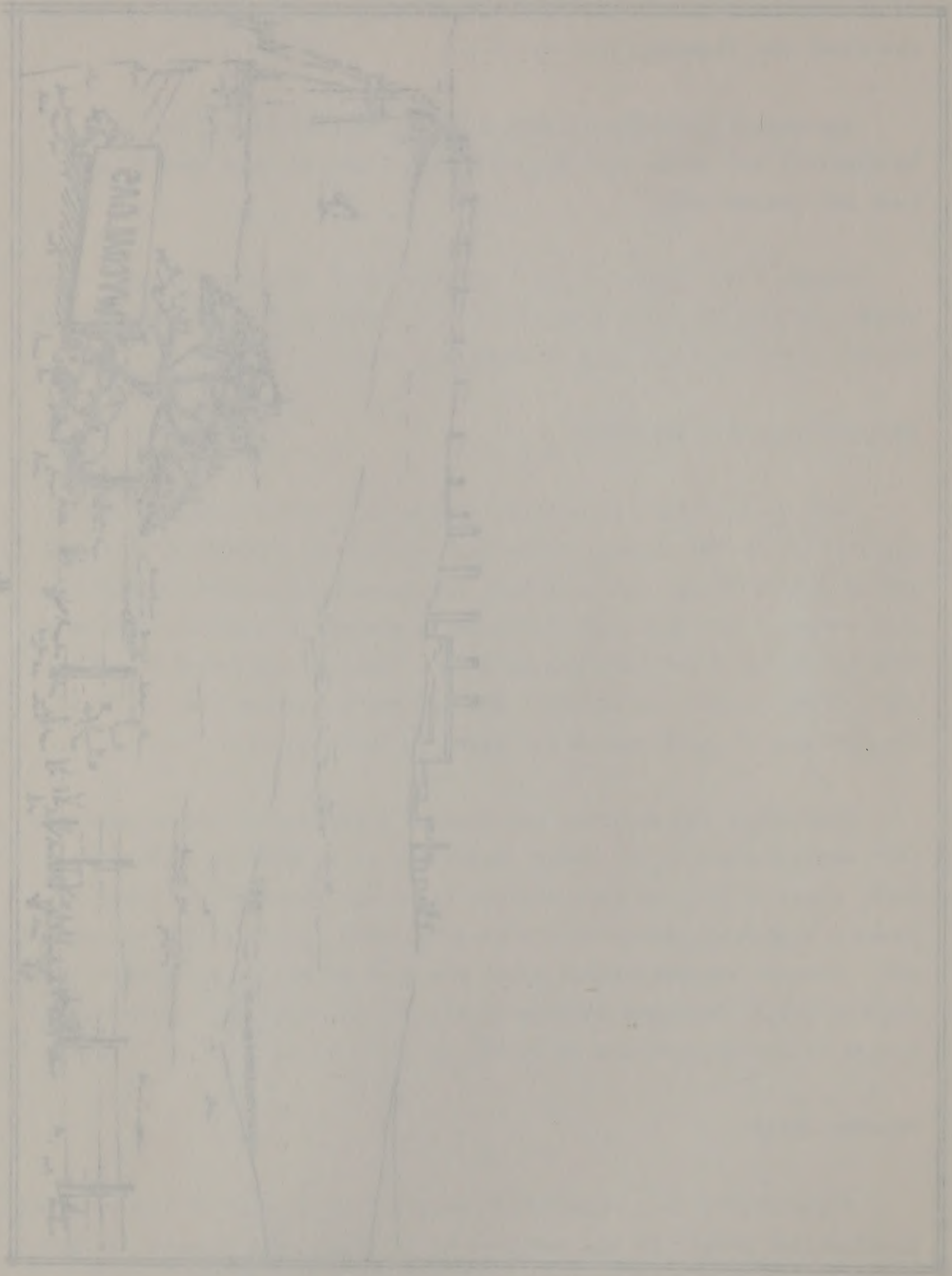
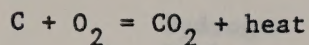


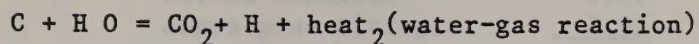
Table 3.3-1

## PRIMARY GASIFICATION REACTIONS, LURGI PROCESS

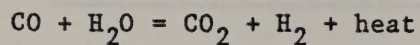
## Combustion:



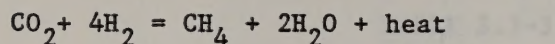
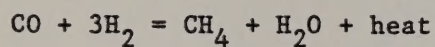
## Gasification:



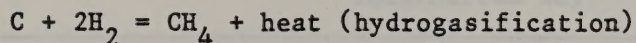
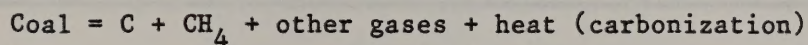
## Shift Conversion:



## Methanation:



## Minor Reactions:



Coal from Mine	37,450	10,520,000
Coal to Gasifiers	22,810	7,790,000
Coal to Refinery	3,710	1,361,000
Waste	30,550	10,141,000
Coal Slime to Refinery	2,070	587,000
TOTAL	66,590	19,339,000

Table 1-1-1

PRIMARY GASIFICATION REACTIONS (Simplified)

Combustion:
$C + O_2 = CO_2 + \text{heat}$
Gasification:
$C + H_2O = CO + H_2 + \text{heat (water-gas reaction)}$
Water-Gas Shift:
$CO + H_2O = CO_2 + H_2 + \text{heat}$
Methanation:
$CO + 3H_2 = CH_4 + H_2O + \text{heat}$
$CO_2 + 4H_2 = CH_4 + 2H_2O + \text{heat}$
Minor Reactions:
$CO_2 + C = 2CO + \text{heat (carbonization)}$
$C + 2H_2 = CH_4 + \text{heat (hydrogenation)}$

TABLE 3.3-2  
PRODUCT GAS COMPOSITION

Component	Vol. %
Hydrogen	3.20
Methane	95.20
Carbon Dioxide	0.58
Carbon Monoxide	0.01
Argon plus Nitrogen	<u>1.01</u>
TOTAL	100.00

TABLE 3.3-3  
OVERALL 300 MMSCFD PLANT COAL BALANCE

	Tons/Stream Day	Tons/Year
Coal from Mine	32,600	10,828,000
Coal to Gasifiers	22,820	7,580,000
Coal to Boilers	<u>7,710</u>	<u>2,561,000</u>
Subtotal	30,530	10,141,000
Coal Fines to Sales	<u>2,070</u>	<u>687,000</u>
TOTAL	32,600	10,828,000

TABLE 1-2-1  
PROPORTION OF COMPOSITION

Component	Vol. %
Hydrogen	1.10
Methane	97.70
Carbon Dioxide	0.70
Carbon Monoxide	0.40
Argon plus Nitrogen	1.90
TOTAL	100.80

TABLE 1-2-2  
OVERALL 100 TONNETS WAST GAS BALANCE

Tons/Year	Tons/Stream Day	
10,878,000	37,600	Coal from Mines
7,300,000	25,600	Coal to Gasifiers
2,361,000	8,100	Coal to Refinery
10,541,000	36,300	Subtotal
687,000	2,300	Coal Flows to Sales
10,878,000	38,600	TOTAL

3-16

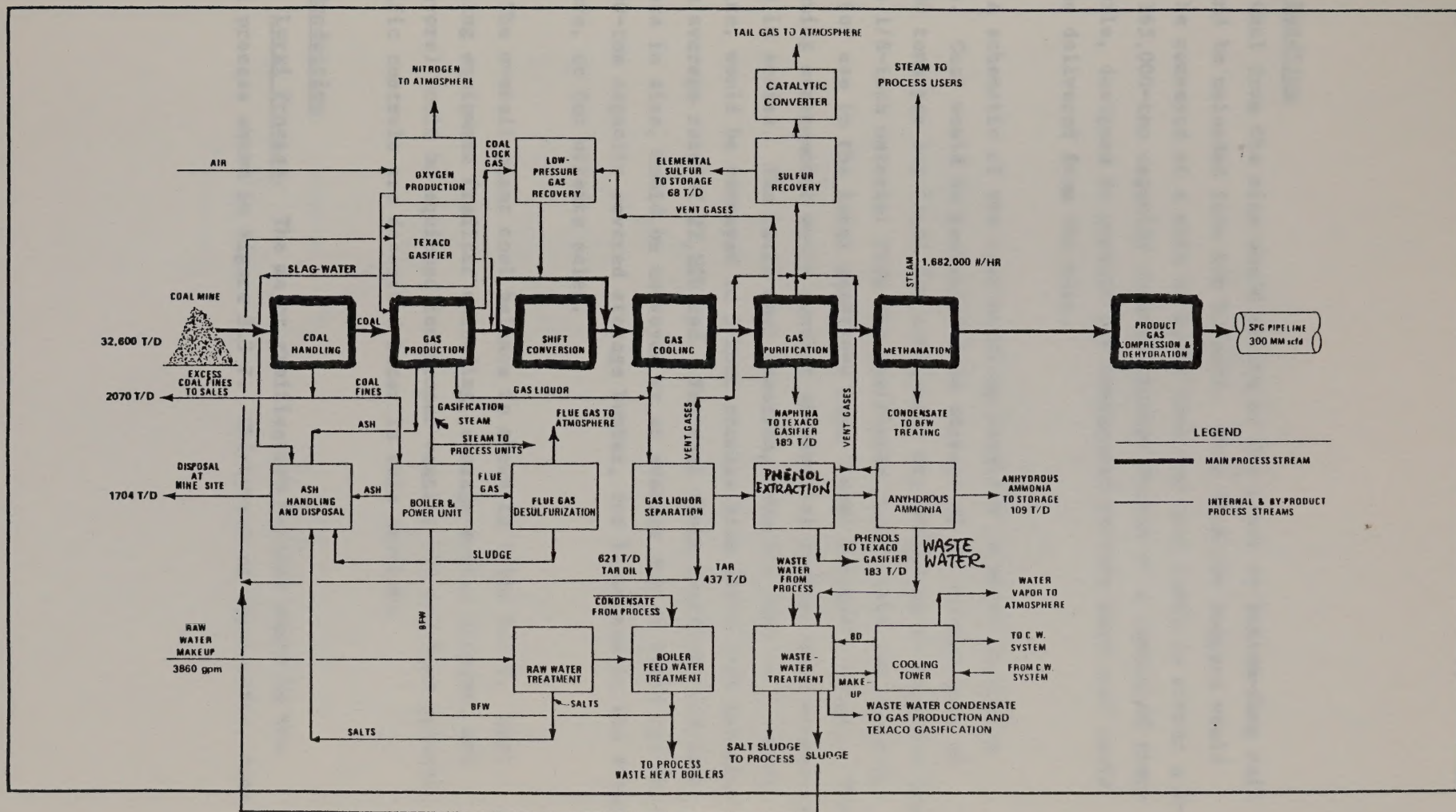
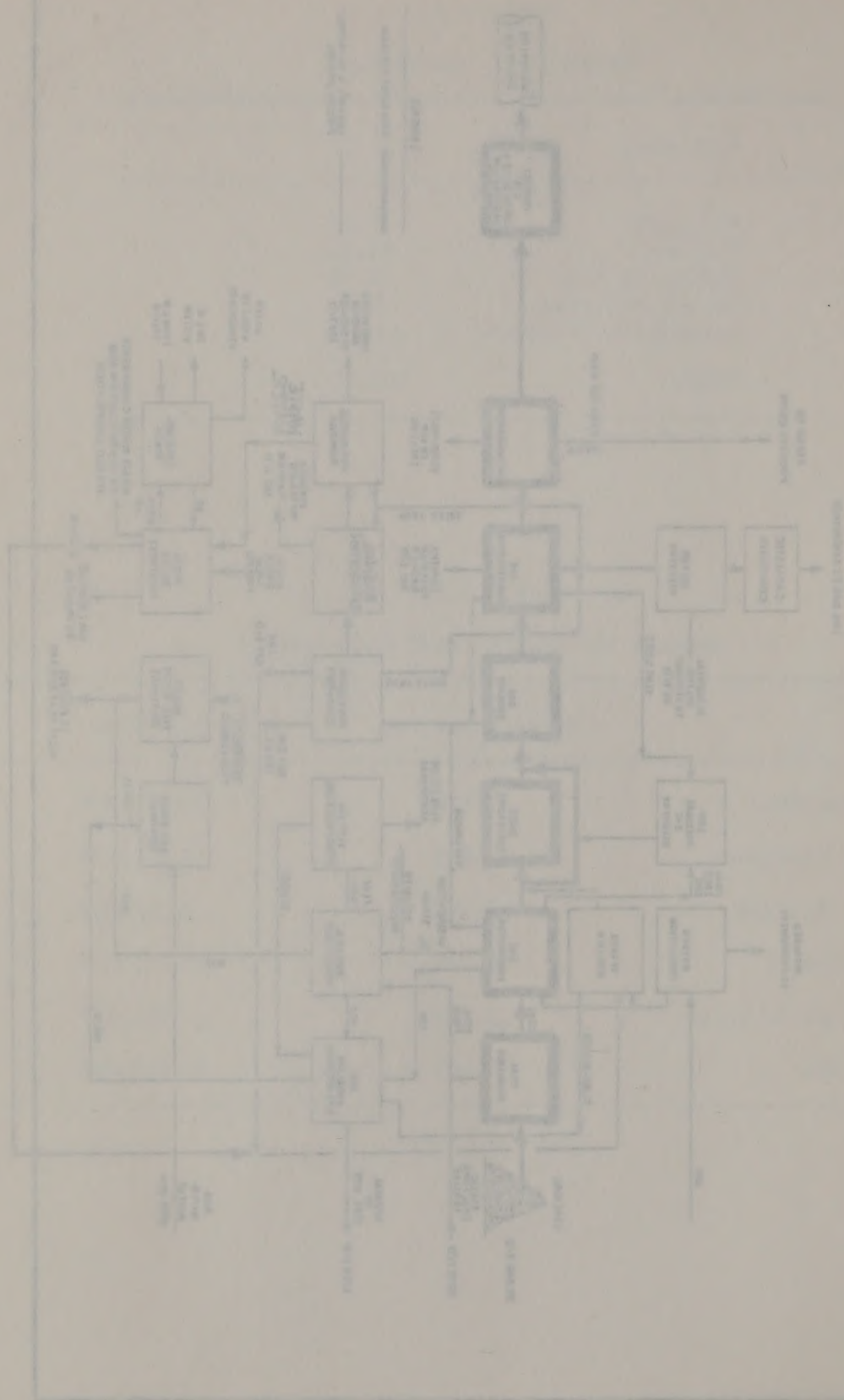


Figure 3.3-5  
SIMPLIFIED PROCESS FLOW DIAGRAM  
FOR COAL GASIFICATION



### Coal Handling

Coal from the mine would arrive at the plant by bottom-dump rail car and be unloaded into two hoppers. Coal from the hoppers would then be conveyed at a rate of 3,000 tons per hour (tph) to either a 5-day, 165,000-ton capacity covered storage bunker or a compacted storage pile, designed to provide for unexpected periods when coal could not be delivered from the mine.

A schematic of the coal handling facility is shown in Figure 3.3-6. Coal would be reclaimed from storage at an average rate of 32,600 tons per day (tpd) for continuous dry screening to separate the minus 1/8-inch material from the gasifiable coal; fines are unacceptable for use in the Lurgi gasifiers (see "Lurgi Process", below). The screening arrangement would consist of parallel trains, with screening steps in series. The large coal fraction, from 1/8 inch to 3 inches in size, would be conveyed to 3-hour storage bins above each gasifier at an average rate of 22,820 tpd. The coal fines fraction, 1/8 inch or less in size, would be conveyed at an average rate of 2,070 tpd to a 24,000-ton capacity covered storage bunker, for later use in the steam boilers, or for offsite sales.

The overall plant coal balance is shown in Table 3.3-3. Coal handling equipment (railcar unloading, storage areas, screens, and conveyors) would be equipped for proper ventilation and dust control. Specific controls are described later in this section.

### Gas Production

Lurgi Process. The major gasification process would be the Lurgi process shown in Figure 3.3-7. Thirty-two of these units, four

### Coal Handling

Coal from the mine would arrive at the plant by conveyor-belt rail car and be unloaded into two hoppers. Coal from the hoppers would then be conveyed at a rate of 1,000 tons per hour (tph) to either a 2- day, 100,000-ton capacity covered storage bunker or a compacted storage pile, designed to provide the unexpected periods when coal could not be delivered from the mine.

A schematic of the coal handling facility is shown in Figure 1.1-1. Coal would be received from storage at an average rate of 12,000 tons per day (tpd) for continuous dry weathering to separate the mine 1/2-inch material from the gasifiable coal. This size material will be used in the large gasifiers (see "Large Gasifiers", below). The screening arrangement would consist of parallel screens, with screening steps in series. The large coal fraction, from 1/2 inch to 2 inches in size, would be conveyed to 2-hour storage bins above each gasifier at an average rate of 12,000 tpd. The coal fines fraction, 1/2 inch or less in size, would be conveyed at an average rate of 1,000 tpd to a 10,000-ton capacity covered storage bunker. The fines are in the stream boiler, or for electric sales.

The overall plant coal balance is shown in Table 1.1-2. Coal handling equipment (crusher, screening, storage bins, conveyor) would be equipped for proper ventilation and dust control. Specific controls are described later in this section.

### Gas Production

Large Process. The major gasification process would be the large process shown in Figure 1.1-3. Thirty-two of these units, four

3-18

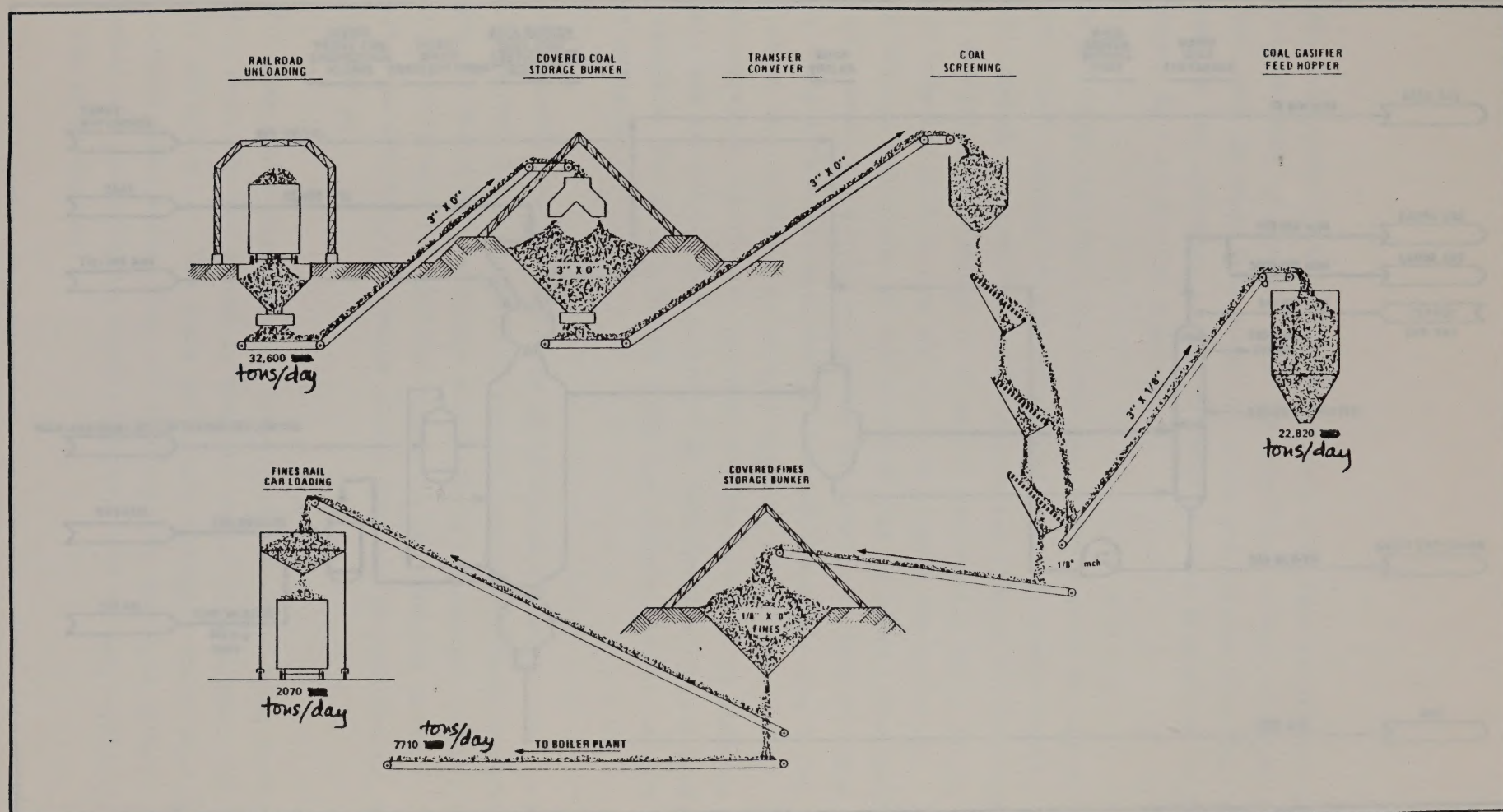


Figure 3.3-6  
GASIFICATION PLANT  
COAL HANDLING AND  
PREPARATION FACILITIES



3-19

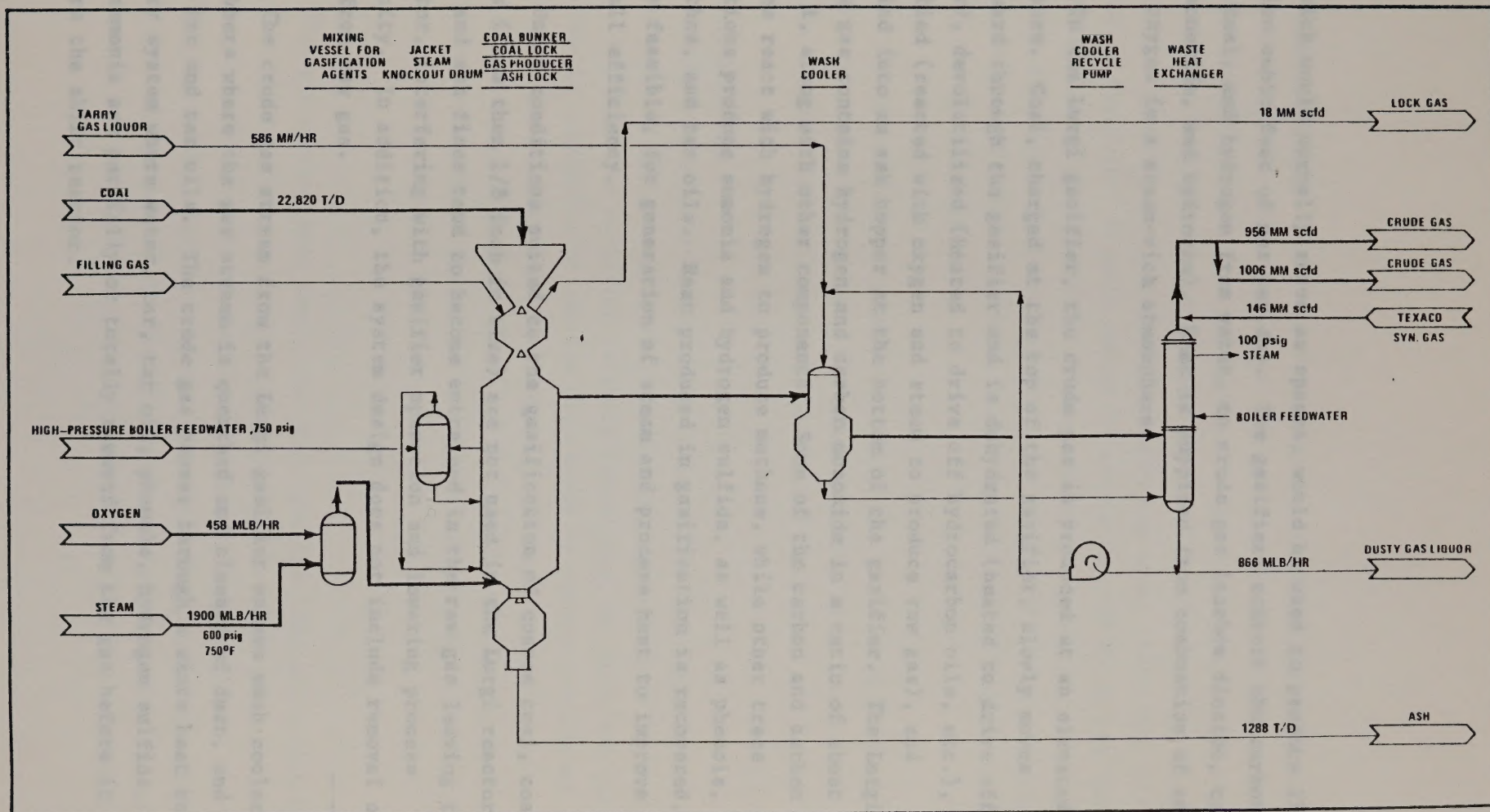


Figure 3.3-7  
LURGI GAS PRODUCTION



of which would normally serve as spares, would be used to produce 278 million cubic feet of gas per day. The gasifiers convert the carbon from coal, and hydrogen from water, to crude gas (carbon dioxide, carbon monoxide, and hydrogen). Heat is supplied from combustion of coal with oxygen in a steam-rich atmosphere.

In the Lurgi gasifier, the crude gas is produced at an elevated pressure. Coal, charged at the top of the gasifier, slowly moves downward through the gasifier and is dehydrated (heated to drive off water), devolatilized (heated to drive off hydrocarbon oils, etc.), gasified (reacted with oxygen and steam to produce raw gas), and emptied into an ash hopper at the bottom of the gasifier. The Lurgi crude gas contains hydrogen and carbon monoxide in a ratio of about 2 to 1, along with other components. Some of the carbon and carbon oxides react with hydrogen to produce methane, while other trace fractions produce ammonia and hydrogen sulfide, as well as phenols, naphthas, and tar oils. Heat produced in gasification is recovered, where feasible, for generation of steam and process heat to improve overall efficiency.

Under conditions suited to the gasification of coarse coal, coal fines (less than 1/8 inch in size) are not used in the Lurgi reactors. Coal and ash fines tend to become entrained in the raw gas leaving the reactor, interfering with gasifier operation and lowering process capacity. In addition, the system design does not include removal of ash from raw gas.

The crude gas stream from the Lurgi gasifier enters wash cooler scrubbers where the gas stream is quenched and cleaned of dust, and some tar and tar oils. The crude gas passes through a waste heat recovery system where water, tar, tar oil, phenols, hydrogen sulfide, and ammonia are partially or totally removed from the gas before it enters the shift reactor.

of which would normally serve as a gasifier, would be used to produce 115 million cubic feet of gas per day. The gasifier converts the carbon from coal, and hydrogens from water, to crude gas (carbon dioxide, carbon monoxide, and hydrogen). Gas is supplied from combustion of coal with oxygen in a steam-plant atmosphere.

In the large gasifier, the waste gas is produced as an elemental gas. Gas, changed at the top of the gasifier, closely approximates the composition of the gasifier and is subjected to heat exchangers, water, and other processes (heat exchangers, etc.) to produce gas. Gasified (cracked) with oxygen and steam to produce raw gas, and subjected into an air heater at the bottom of the gasifier. The large crude gas contains hydrogen and carbon monoxide in a ratio of about 1 to 1, along with other components. Some of the carbon and carbon oxides react with hydrogen to produce methane, while other carbon fractions produce ammonia and hydrogen sulfide, as well as phenols, naphthalene, and tar oils. Heat produced in gasification is recovered, where feasible, for generation of steam and process heat to improve overall efficiency.

Under conditions related to the gasification of waste coal, coal fines (less than 1/8 inch in size) are not used in the large reactor. Coal and ash fines tend to become entrained in the gas leaving the reactor, interfering with gasifier operation and lowering process capacity. In addition, the system design does not include removal of ash from the gas.

The crude gas stream from the large gasifier contains water, carbon dioxide, and other gases which are removed and cleaned of dust, and some tar and oil. The crude gas passes through a water wash to remove system water, tar, tar oil, phenols, hydrogen sulfide, and ammonia are partially or totally removed from the gas before it enters the shift reactor.

Texaco Process. The recovered phenols, naphtha, tar, and tar oil (about 120,000 pounds per hour) are charged to the Texaco Synthesis Gas Generation Unit for gasification. Here steam/water and oxygen are mixed at an elevated temperature and pressure. The Texaco synthesis gas is quenched and scrubbed to remove any soot. This soot is returned to the unit. A small amount of ash is removed by an ash lock on the bottom of the gasifier. The synthesis gas produced contains hydrogen and carbon monoxide in a ratio of about 0.8 to 1.0 along with small amounts of other components including methane, nitrogen, argon, water, and hydrogen sulfide.

Enough additional pipeline-quality gas would be produced by the Texaco process to increase the plant capacity by at least 22 MMSCFD. Figure 3.3-8 illustrates the flow of this unit.

#### Shift Conversion

The hydrogen-to-carbon-monoxide ratio of the crude gas is too low for subsequent methane synthesis. Therefore, approximately 51 percent of the crude gas is subjected to shift conversion, in which the carbon monoxide is catalytically reacted with steam to produce additional hydrogen and carbon dioxide. The remaining gas bypasses shift conversion and is mixed with the shifted gas following cooling; see below. Shift conversion would occur in two parallel trains, each capable of processing 60 percent of the feed gas.

#### Gas Cooling

The gas cooling unit cools the crude gas from the gas production unit and the converted gas from shift conversion. This unit is designed for efficient use of waste heat otherwise rejected into the air and cooling water. Heat is removed in two parallel trains of equipment, and segregation of the two gas streams is maintained within each processing train. After recompression of the shifted gas stream, the



3-22

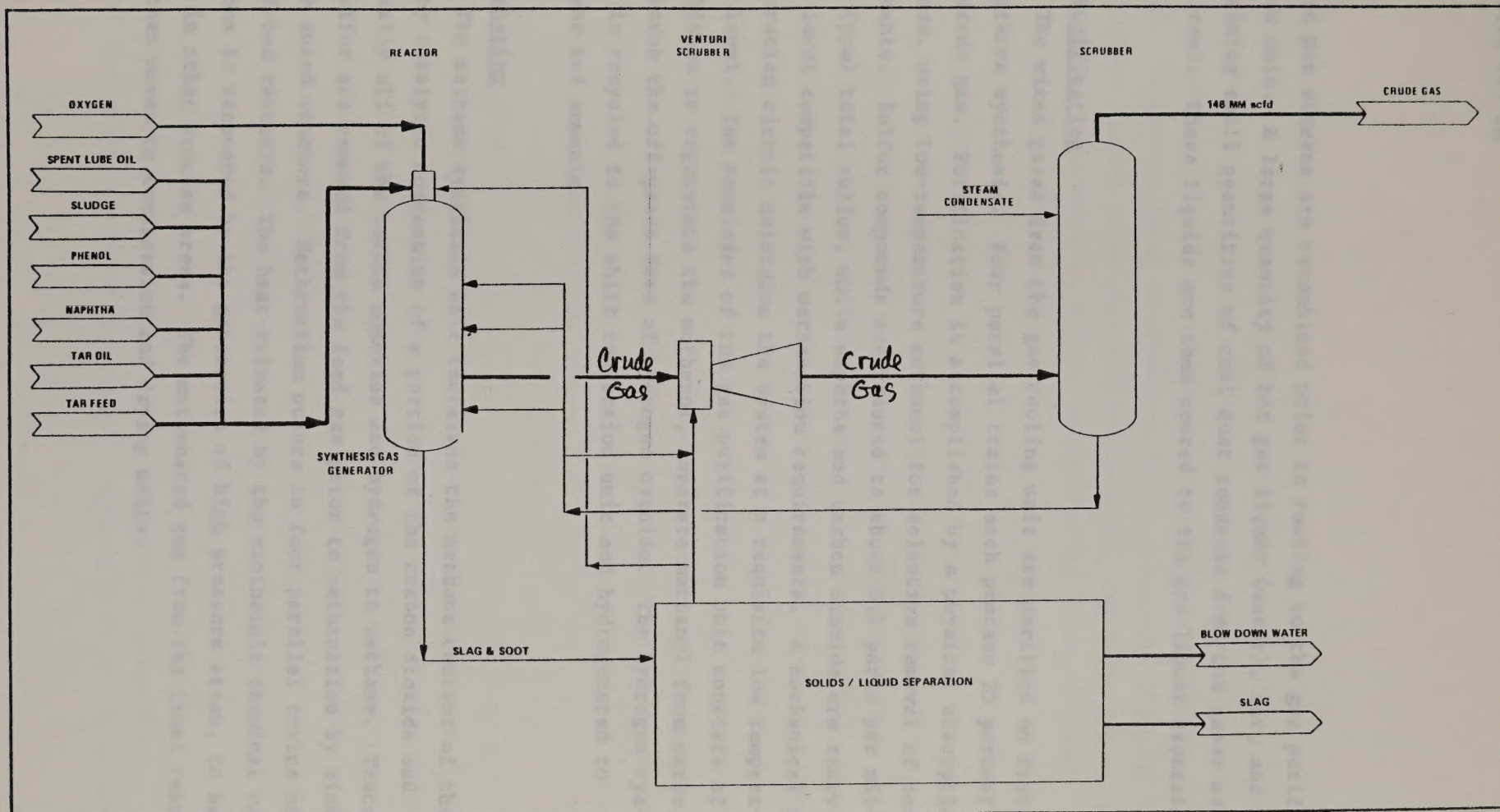
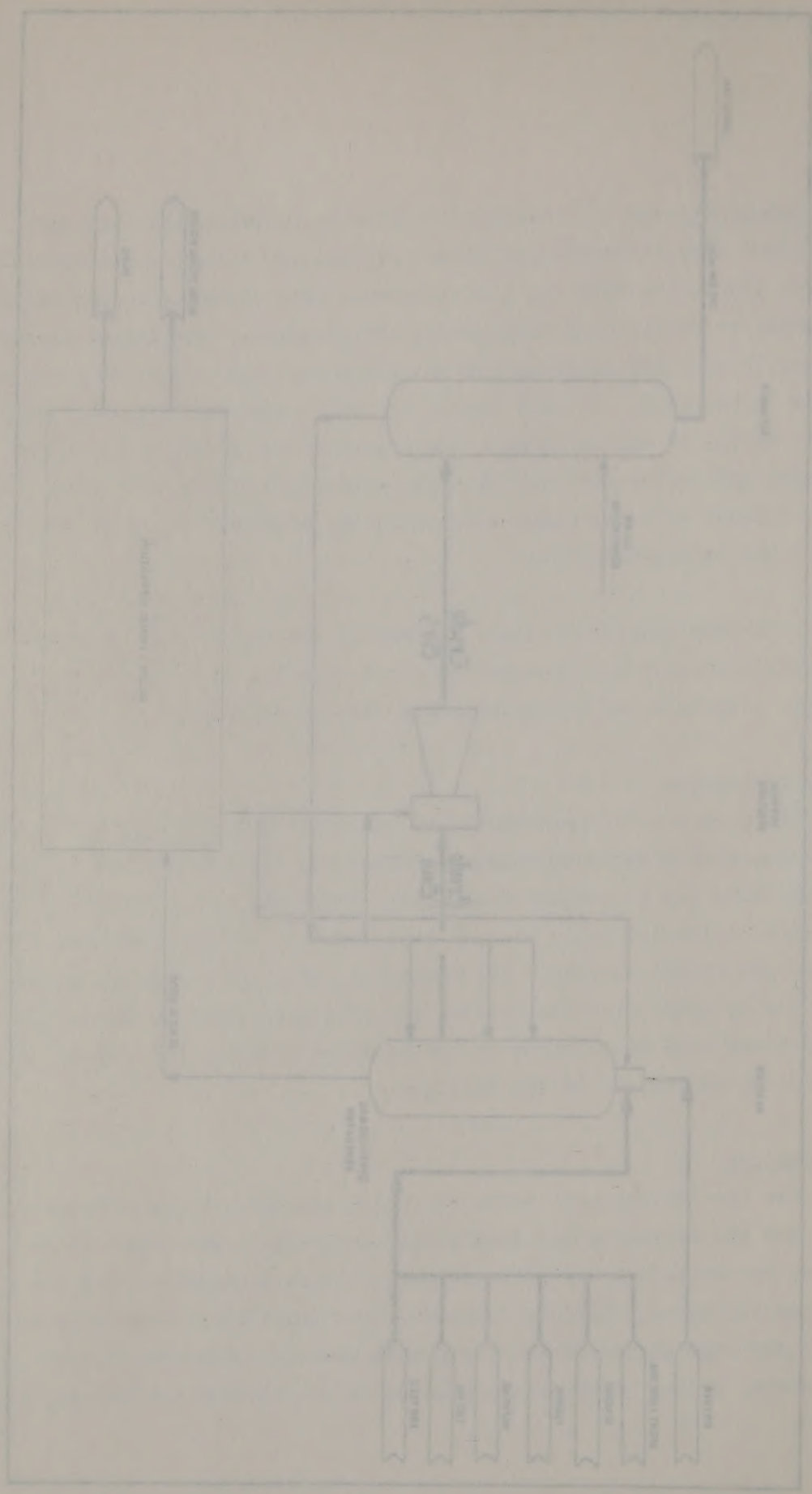


Figure 33-8  
TEXACO GASIFIER SYSTEM



cooled gas streams are recombined prior to routing to the gas purification unit. A large quantity of hot gas liquor (water), tar, and oil containing small quantities of coal dust condense from the gases as they cool. These liquids are then routed to the gas liquor separation unit.

### Gas Purification

The mixed gases from the gas cooling unit are purified en route to methane synthesis. Four parallel trains each process 25 percent of the crude gas. Purification is accomplished by a physical absorption process, using low-temperature methanol for selective removal of contaminants. Sulfur compounds are reduced to about 0.1 parts per million (ppm) total sulfur, while naphtha and carbon dioxide are removed to a level compatible with methanation requirements. A mechanical refrigeration circuit maintains the system at a requisite low temperature level. The remainder of the gas purification unit consists of facilities to regenerate the methanol, separate methanol from water, and scrub the off-gases free of hydrogen cyanide. The hydrogen cyanide is recycled to the shift conversion unit and hydrogenated to methane and ammonia.

### Methanation

The methane synthesis unit increases the methane content of the gas by catalytic conversion of a portion of the carbon dioxide and virtually all of the carbon monoxide and hydrogen to methane. Traces of sulfur are removed from the feed gas prior to methanation by zinc oxide guard reactors. Methanation occurs in four parallel trains of fixed-bed reactors. The heat released by the exothermic chemical reactions is recovered by the generation of high pressure steam, to be used in other process areas. The methanated gas from the final reactor then moves to compression and drying units.

cooling gas systems are recommended prior to cooling to the gas outlet. A large quantity of hot gas (about 1000° F.) and oil containing small quantities of coal dust combine from the gases as they cool. These liquids are then cooled to the gas liquor separation unit.

### Gas Purification

The waste gases from the gas cooling unit are purified as follows in various systems. Four parallel systems each process 15 percent of the waste gas. Purification is accomplished by a physical absorption process, using low-temperature methanol for selective removal of compounds. Sulfur compounds are reduced to about 0.1 parts per million (ppm) level, while nitrogen and carbon dioxide are removed to a level compatible with methanation requirements. A mechanical refrigeration circuit maintains the system at a temperature low enough to absorb the gas. The remainder of the gas purification unit consists of facilities to regenerate the methanol, separate methanol from water, and scrub the off-gases free of hydrogen cyanide. The hydrogen cyanide is recycled to the shift coprocession unit and hydrogenated to methane and ammonia.

### Methanation

The methanation system will decrease the methane content of the gas by catalytic conversion of a portion of the carbon dioxide and virtually all of the carbon monoxide and hydrogen to methane. These are removed from the feed gas prior to methanation by steam and sulfur gas removal. Methanation occurs in four parallel trains of fixed-bed reactors. The heat released by the exothermic chemical reaction is recovered by the generation of high pressure steam, to be used in other process areas. The methanated gas from the final reactor then goes to compression and drying units.

### Compression and Drying

Compression of the product gas to pipeline pressure occurs in a single-train steam-turbine-driven compressor. Two stages of compression are required, with intercooling, after-cooling, and condensate removal. To prevent water condensation in the subsequent pipeline transmission system, glycol dehydration is used. The water remaining in the product gas would be about 7 lb per million standard cubic feet, or less than 170 ppm.

### Gas Liquor Separation

The gas liquor separation unit produces a three-phase separation between oil, gas liquor, and tar. Feed streams consist of dusty and oily gas liquor from the gasification unit, and oily gas liquor from gas cooling. Tar separated in this unit is dried by vacuum distillation or other means, to remove water prior to Texaco gasification. Also processed in this unit are flash gases resulting from the initial pressure reductions of the two gas liquor feeds. These gases are scrubbed with water to remove ammonia, and processed in the sulfur recovery unit. Two trains of equipment process dusty gas liquor, and a single train processes oily gas liquor.

### Phenol Extraction

The Lurgi Phenosolvan process removes phenols from the gas liquor leaving the separation unit. The gas liquor is contacted with di-isopropyl ether in multistage countercurrent extractors. Phenols are extracted and the solvent is recovered for reuse. Following phenol extraction, ammonia, hydrogen sulfide, and carbon dioxide are removed from the dephenolized gas liquor in a two-stage stripping system.

### Ammonia Recovery

Ammonia removal is necessary before the water is processed through biological treatment and reused. Additionally, the recovered

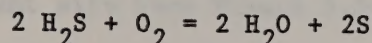


ammonia is a marketable product. To recover ammonia, dephenolized water containing acid gases (carbon dioxide and hydrogen sulfide) and ammonia enters a nitrogen stripper column, where any remaining phenol removal solvent is recovered and recycled. The water stream then enters an ammonia-stripping section, where the remaining acid gases and ammonia are driven to the top scrubber section of the column. A phosphate solution chemically absorbs ammonia from the acid gases exiting the top of the column. The acid gases flow to sulfur recovery while the phosphate/ammonia solution flows to the stripper column. Ammonia and water vapor driven out of the phosphate solution enter the ammonia fractionator where the water is removed, leaving anhydrous ammonia. The recovered water is recycled. Reclaimed phosphate off the bottom of the stripper is recirculated to the top scrubber section of the column.

#### Sulfur Recovery

The acid gases from the gas purification unit, gas liquor separation, and phenol extraction are combined and treated by the Stretford process, for hydrogen sulfide removal and conversion to elemental sulfur. The unit is designed to reduce the hydrogen sulfide concentration in the final tail gas to less than 100 ppm. Molten sulfur recovered by this process would have a purity of at least 99.5 percent.

The Stretford process is a countercurrent absorption process using a sodium carbonate solution with other chemical additives as the absorbing medium. The overall chemical reaction, including absorption and regeneration, is written as follows:



Organic sulfur compounds from the feed gas are absorbed and converted by the Stretford solution. Two parallel Stretford units



would be used, each processing 50 percent of the acid gas feed. Treated tail gas leaves the absorber and is routed to a catalytic converter for disposal of residual hydrocarbon fractions.

## SUPPORT UNITS

### Water Supply

Yearly process (non-potable) water requirements and a plant water balance are shown in Table 3.3-4. Over 20 percent of operational water needs would be supplied from coal moisture.

Raw water would be brought into the plant through a pipeline (see section 3.6) terminating in a 5-acre, onsite storage impoundment. This impoundment would be large enough to provide all plant makeup requirements for 4 days, at full capacity. It would also provide water for fire fighting.

Water from the impoundment would be pumped to cold lime treaters, where it would be clarified and softened with cold lime, magnesium oxide, and soda ash. The treated water would be filtered, then pumped into a header which supplies water for the boiler feedwater makeup treating system. No further treatment of this water would be required prior to its use as utility cooling tower makeup water. Underflow from the clarifier would be pumped to a settling pond where the water would be decanted from the suspended solids and reclaimed.

Potable water requirements during plant operation would be approximately \_\_\_\_\_ gpd, to be furnished from two wells to be drilled at the plant site (see Figure 3.3-2).

### Steam and Power Generation

Necessary steam requirements for the overall plant would be met through onsite generation. The steam generation facilities would



TABLE 3.3-4

SUMMARY WATER BALANCE FOR  
COAL GASIFICATION PLANT OPERATION

<u>Water Sources</u>	<u>GPM</u>	<u>Acre-Ft./Year</u>
<b>Inputs</b>		
Raw Water	3,860	6,020
Coal Moisture	1,065	1,718
Miscellaneous	<u>76</u>	<u>123</u>
<b>TOTAL</b>	<b>5,001</b>	<b>7,861</b>
<b>Outputs</b>		
Process Consumption	1,297	2,092
Losses to Atmosphere		
Process Area	118	190
Cooling Tower	2,200	3,549
Utility Area	677	1,092
Water Treating Area	60	97
Miscellaneous	<u>362</u>	<u>378</u>
<b>SUBTOTAL</b>	<b>3,417</b>	<b>5,306</b>
In Ash	118	190
In Sludges	<u>169</u>	<u>273</u>
<b>SUBTOTAL</b>	<b>287</b>	<b>463</b>
<b>TOTAL</b>	<b>5,001</b>	<b>7,861</b>



consist of a combination of process waste heat exchangers, and boilers fired by coal fines. Electrical power would be generated on-site for plant operations; electrical power for the water supply system and electric railroad would be purchased from the Pacific Power and Light Company; refer to section 3.8 for further discussion of electrical power supply.

Steam would be used in the gasification process and in support facilities as follows:

- gasification reactant and temperature moderator
- motive power for air and gas compression
- electric power generation
- process heat for fractionation and purification
- liquid fuel dispersion in burners
- motive power for various pumps
- freeze protection

Steam generated by waste heat available in the methanation step, and from the coal-fired boilers, would drive the steam turbines throughout the plant, including those for electric generation, and would also provide process steam for gasification. The steam turbine units would be equipped with air-cooled surface condensers to minimize cooling water requirements. Condensate would be returned to the boiler feed-water system. Remaining waste heat exchangers within the gasification train would provide low pressure steam, sufficient to supply energy for process heat requirements.

Current plant design calls for five boilers, each with a capacity of 1,000,000 pounds (lb) of steam per hour, and three 35-megawatt turbogenerators. All units would be operational at any given time, normally at 70 to 80 percent of capacity; this would provide sufficient reserve capacity to avoid a plant shutdown, should one of the units fail.

consist of a combination of ground water pump, compressor, and boiler  
 fired by coal. Electrical power would be generated on-site for  
 plant operations; electrical power for the water supply system and  
 electric fuel would be purchased from the local power and light  
 company; water to section 5.5 for further discussion of electrical  
 power supply.

Steam would be used in the gasification process and in support  
 facilities as follows:

- gasification reactor and temperature monitor
- turbine power for air and gas compressor
- electric power generation
- process heat for liquefaction and gasification
- liquid fuel dispersion in burner
- motive power for various pumps
- process protection

Steam generated by waste heat available in the gasification area, and  
 from the coal-fired boiler, would drive the steam turbines throughout  
 the plant, including those for electric generation, and would also  
 provide process steam for gasification. The steam turbine waste heat  
 is rejected with air-cooled surface condensers to minimize cooling wa-  
 ter requirements. Condensate would be returned to the boiler feed-  
 water system. Remaining waste heat exchangers within the gasification  
 train would provide low-pressure steam, sufficient to supply energy  
 for process heat requirements.

Current plant design calls for five boilers, each with a capacity  
 of 1,000,000 pounds (lb) of steam per hour, and three 35-megawatt tur-  
 bogenerators. All units would be operational at any given time, nor-  
 mally at 70 to 80 percent of capacity; this would provide sufficient  
 reserve capacity to avoid a plant shutdown, should one of the units  
 fail.

### Cooling Water System

The cooling water system is designed to circulate 75,000 gpm of water for use in plant processes requiring a process temperature lower than 130°F. To conserve water, air cooling would be used on higher temperature streams. Since the plant is designed for zero aqueous effluent, the multi-cell, forced-draft cooling towers would be designed to evaporate potential effluent streams such as reclaimed phenolic process water. Make-up water for the cooling towers would come primarily from the Phenosolvan unit after ammonia removal, bio-oxidation and evaporation. Biocides, corrosion inhibitors, and pH control chemicals would be added to the circulation water to keep corrosion and fouling effects within acceptable operating limits; however, no chromates would be used in the towers. Blowdown from the cooling tower would be used as makeup water to the evaporation system.

### Oxygen Plant

Gasifier facilities require oxygen of 98 percent purity. To meet this need, the oxygen plant would consist of two identical parallel trains, each capable of producing half the required amount of oxygen. The principal elements of these units would be air compression; cryogenic fractionation of oxygen from other air components, mainly nitrogen; and compression of product oxygen to gasifier pressure. Onsite liquid oxygen storage would be provided.

### Plant Flare System

Emergency pressure reliefs would be routed into the flare system. Design load is based upon the emergency relief of total crude gas production. The flare would be designed for smokeless operation.

### Tankage

Tankage at the plant site would provide storage capacity for:

### Cooling Water System

The cooling water system is designed to circulate 15,000 gpm of water for use in plant processes requiring a constant temperature lower than 150°F. To conserve water, air cooling would be used on higher temperature streams. Since the plant is designed for zero emissions of liquid, the water-cooled cooling towers would be designed to evaporate potential effluent streams such as residual phenolic process water. Make-up water for the cooling towers would come primarily from the hydrocarbon unit effluent streams (water, hydrocarbon and wastewater). Recycled, corrected inhibitors, and the control chamber would be added to the circulation water to keep corrosion and fouling effects within acceptable operating limits; however, no additional water would be used in the towers. Recycled from the cooling tower would be used as makeup water in the wastewater system.

### Process Effluent

Gasifier effluents require oxygen of 25 percent purity. To meet this need, the oxygen plant would consist of two identical parallel trains, each capable of producing half the required amount of oxygen. The principal elements of these trains would be air compressor, cryogenic fractionation of oxygen from other air components, mainly nitrogen, and compression of product oxygen to gasifier pressure. Gasifier liquid oxygen storage would be provided.

### Plant Effluent System

Emergency pressure relief would be routed into the effluent system. Design load is based upon the emergency relief of total crude gas production. The effluent would be designed for continuous operation.

### Technology

Technology at the plant site would provide storage capacity for

- Liquid streams between consecutive process steps, to ensure smooth operation of the system.
- Major flows such as the main boiler feedwater makeup.
- Emergency gas liquor flows that must be diverted from their normal routing due to outages of process equipment downstream. The storm water collection basin would be partitioned off to accept Phenosolvan effluent or other gas liquor flows diverted in the event of system upset. Provision would be made to reclaim such diverted gas liquor flows and reintroduce them into the system.
- Process by-products prior to their sale.
- Chemicals, catalysts, and additives for plant use.

Tankage containing volatile liquids would be equipped with floating roofs to prevent escape of vapors to the atmosphere. Propylene would be stored in pressure vessels, while anhydrous ammonia would be stored in refrigerated storage tanks. Dikes would be provided around tanks, to contain liquids in the event of structural failure. Drain hubs would be provided adjacent to such tankage to permit drainage to the oily waste sewer for treatment and reclamation, or disposal. A summary of tankage required for produced and raw materials is given in Table 3.3-5.

#### Auxiliary Buildings

In addition to the process, control, electrical, and miscellaneous operating area buildings included in individual areas, a number of general plant buildings would be required. These are summarized as follows:



TABLE 3.3-5

## SUMMARY OF THE STORAGE FACILITIES OF THE WYCOALGAS COMPLEX

<u>Stored Materials</u>	<u>Storage Vessel Capacity, gal.</u>	<u>Number of Vessels</u>	<u>Storage Temperature °F</u>	<u>Type of Storage Vessel</u>
RAW MATERIALS				
No. 2 Fuel Oil	30,000	2	Ambient <sup>a</sup>	Fixed Roof <sup>b</sup>
Liquid Oxygen	1,350 tons	2	Refrigerated	- <sup>c</sup>
50% Sodium Hydroxide (Aqueous Solution)	31,500	2	Ambient	Fixed Roof
Methanol	252,000	2	Ambient	Fixed Roof/Vapor Recycled to Gasification Complex
Di-isopropyl Ether	31,500	2	Ambient	Fixed Roof with Vapor Recovery System
Propylene	33,600	2	Ambient	Pressurized Tank
Triethylene Glycol	10,000	1	Ambient	Fixed Roof
Sulfuric Acid	20,000	1	Ambient	Fixed Roof
Phosphoric Acid	10,000	1	Ambient	Fixed Roof
PRODUCED MATERIALS				
Anhydrous Ammonia	5,000 tons	2	Refrigerated	-
Molten Sulfur	1,000 tons	2	-	Fixed Roof
Slop Oil <sup>d</sup>	4,700	2	Ambient	Fixed Roof
Crude Phenols <sup>d</sup>	462,000	2	140	Fixed Roof
Naphtha <sup>d</sup>	630,000	2	100	Floating Roof
Tar <sup>d</sup>	1,092,000	2	160	Fixed Roof
Tar Oils <sup>d</sup>	1,680,000	2	100	Fixed Roof

<sup>a</sup>55°F is the average annual temperature.<sup>b</sup>Fixed roof implies fixed roof with a conservation vent.<sup>c</sup>Vessel specification not included in petroleum storage vessel performance standards.<sup>d</sup>Feedstock for Texaco Gasification (interim storage).



- administration office building
- operations/laboratory building
- guard house
- fire station and safety building
- maintenance shop and garage building
- warehouse and parts storage building
- chemical storage building

#### WASTE WATER RECOVERY, TREATMENT, AND REUSE

The function of the waste water treatment system would be to reduce the contaminants present in plant waste water and storm water streams so that the water can be reclaimed for use either as boiler feedwater or as cooling tower makeup water. This is in keeping with the overall objective of zero aqueous plant discharge and a minimum demand for offsite water. The system would collect and treat all the plant's waste water and storm water streams in a bio-oxidation unit to reduce the organic and fatty acid compounds. This effluent would then be evaporated to extract organic and inorganic dissolved solids. Distillate from evaporation would then be reused as process water. The principal waste streams treated are listed in Table 3.3-6, and Figure 3.3-9 is a schematic diagram of the treatment system. Refer also to Figure 3.3-3. A description of the elements of the system is presented below.

#### Storm Water Collection System

Storm water runoff would be collected in three plant site areas, prior to being pumped to pretreatment and treatment. The ten-year, 24-hour rainfall event for the site is approximately 26 inches; the three ponds described below are designed to accommodate roughly 2 1/2 times this volume.



TABLE 3.3-6

## QUANTITY AND NATURE OF MAJOR WASTE WATER STREAMS

Stream	Volume (gpm)	Wastewater Constituents
Phenosolvan Effluent	3,000	High in $\text{NH}_3$ , $\text{H}_2\text{S}$ , high- and low-boiling organics, fatty acids, and dissolved solids.
Oil Sewer	160	Oily with suspended solids.
Sanitary Waste	25	Municipal sewage.
Storm and Fire Water	80	Suspended solids.
Selected Blowdowns	440	Non-oily, with moderate dissolved solids.



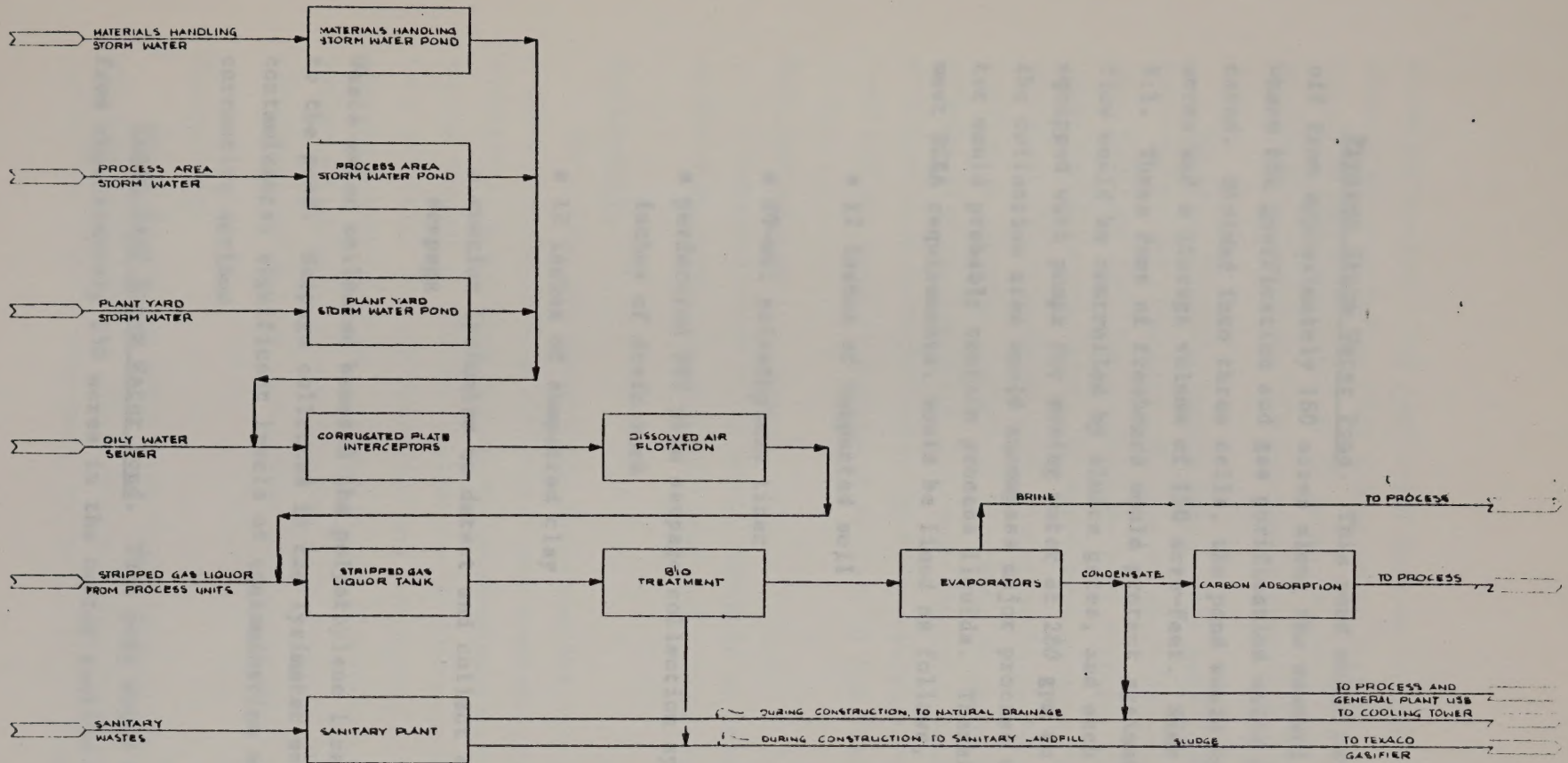


Figure 3.3- 9  
Waste Water and Stormwater Treatment  
System, Gasification Plant



Process Storm Water Pond. This pond would collect surface runoff from approximately 180 acres along the western side of the site, where the gasification and gas purification units and tankage are located. Divided into three cells, the pond would have an area of 10 acres and a storage volume of 150 acre-feet. Side slopes would be 3:1. Three feet of freeboard would protect against overfilling. Inflow would be controlled by sluice gates, and each cell would be equipped with pumps for moving water at 280 gpm to treatment. Since the collection area would encompass major process units, impounded water would probably contain process liquids. Therefore the pond, to meet RCRA requirements, would be lined as follows, from top to bottom:

- 12 inches of compacted soil
- 80-mil polyethylene liner
- perforated PVC pipe seepage collection system set in 12 inches of drain rock
- 12 inches of compacted clay
- suction lysimeter to detect and collect any additional seepage

Waste water collected beneath the polyethylene liner would be returned to the pond. Seepage collected in the lysimeter would be analyzed for contaminants; significant levels of contamination would trigger corrective actions.

Plant Yard Storm Water Pond. This pond would collect runoff from approximately 130 acres in the center section of the site, where



would be located. The pond would have an area of 9 acres and a capacity of 67 acre-feet. Side slopes would be 3:1. Pumps would be capable of withdrawing water at 80 gpm. The pond base would be prepared by cleaning, grubbing, discing, and recompaction; no liner is planned.

Material Handling Runoff Pond. This pond would collect runoff from within the rail loop, an area of about 340 acres which contains coal handling facilities, inactive coal storage, and the interim solid waste (ash) storage area. It would have an area of 20 acres and a volume of 244 acre-feet. Side slopes would be 3:1. Pumps would be capable of removing liquids to treatment at up to 190 gpm. Runoff may contain minerals dissolved from coal and ash. Since these wastes are anticipated to be nonhazardous by RCRA standards, no liner is planned; construction would be identical to that of the Plant Yard Pond.

#### Oily Water Sewer

A separate sewer would drain, directly to pretreatment, all areas of the site subject to possible leaks of oily materials.

#### Pretreatment

Water from the storm water ponds and the oily water sewer would require pretreatment to remove oil and suspended solids, prior to biotreatment. A two-step mechanical pretreatment would remove entrained solids and oil by gravity separation in a corrugated-plate interceptor, and would extract dissolved and emulsified oil and finely-dispersed particles in a dissolved air flotation unit. The effluent would be combined, in surge tanks, with stripped process water from the phenol extraction unit, prior to biotreatment.

#### Biotreatment

Stripped process water from Phenol extraction and other process units contains ammonia ( $\text{NH}_3$ ), hydrogen sulfide ( $\text{H}_2\text{S}$ ), high- and low-boiling organic compounds, fatty acids, and dissolved solids.



This effluent, and the relatively smaller volume of storm water, would be treated by bio-oxidation, using 98 percent pure oxygen in an activated sludge treatment system. Outputs would be carbon dioxide CO<sub>2</sub> water, and sludge. The sludge would be gasified in the Texaco reactors, and the treated water would be routed to a mechanical evaporation unit.

#### Mechanical Evaporation

Biotreatment effluent would be distilled to remove dissolved solids and further reduce dissolved organic compounds. Outputs would be concentrated brine, to be used for ash sluicing and other process functions, and distillate, which would then move to a carbon adsorption unit prior to becoming boiler feedwater.

#### Carbon Adsorption

Boiler feedwater must be of high quality to avoid fouling and corrosion. Carbon adsorption would further reduce organic compounds, and the output of this unit would then go to the plant boilers.

#### Sanitary Waste Treatment

A separate activated sludge treatment system would be used to process sanitary wastes to such a level that effluent could be used as cooling tower makeup water. Sludge from this system would be gasified in the Texaco gasifier.

#### Solar Evaporation Pond

This pond would be used strictly for solar evaporation of permanently-impounded boiler rinse solution. The pond would have an area of 1.75 acres and a volume of 7 acre-feet, with 3 feet of freeboard.



Side slopes would be 3:1 inside and 2:1 outside. The pond would contain 500,000 gallons of boiler rinse water during the first year, and 833,000 gallons thereafter. A second pond would be used only as a spare. Boiler rinse solution would contain:

- Hot alkaline flush containing
  - 1 percent trisodium phosphate
  - 0.05 percent Bennoz "2A1"
  - 0.05 percent Rohm & Haas "+101"
  - 10 ppm Dow-Corning "Anh-foam B"

- Acid cleaning solution containing

- 2 percent hydroxyacetic acid
- 1 percent formic acid
- 0.25 percent inhibitor
- 0.025 percent wetting agent
- 0.25 percent ammonium B fluoride

To meet RCRA standards, this pond would be lined and monitored identically to the process storm water pond.

#### CONTROL OF AIRBORNE EMISSIONS

Emissions control equipment and procedures represent Best Available Control Technology (BACT) for all project components. Technologies that would be used include:

- Dust suppression and/or collection for coal and ash handling
- Boiler design for control of  $\text{NO}_x$ , electrostatic precipitation for suspended particle control, and flue gas desulfurization for  $\text{SO}_2$  control from the steam generation boilers



- Stretford sulfur recovery for  $\text{SO}_2$  from the gasification units
- Vapor control of hydrocarbon emissions from storage tanks
- Good housekeeping and maintenance procedures for the control of hydrocarbon emissions due to leaks from valves, flanges, and pump seals.

Table 3.3-7 is a summary of plant emission controls. For a more detailed discussion, refer to the Meteorology and Air Quality Technical Report.

#### SOLID WASTE MANAGEMENT

The proposed project would produce large amounts of coal ash, from the gasifiers and from the steam generating boilers, and flue gas desulfurization (FGD) sludge; several other wastes would be produced in smaller volumes. Solid waste production is summarized in Table 3.3-8. In the discussion below, each of these wastes is characterized; following this, the solid waste facilities at the plant are described.

#### Waste Characterization

Gasifier Ash and Texaco Slag. Two types of gasifier ashes or slags would be produced by the gasification plant process: Lurgi gasifier ash and Texaco slag and soot. Both of these wastes would be classified as nonhazardous under RCRA.

Lurgi gasifier ash is similar to ash from conventional coal combustion, but with higher levels of residual carbon. It is gravel-sized, similar to boiler bottom ash. Table 3.3-9 presents a mineral analysis of gasifier ash from a coal similar to the Roland coal that



Table 3.3-7

## SUMMARY OF EMISSION CONTROL EQUIPMENT, GASIFICATION PLANT

Emission Source or Process	Controlled Pollutants	Pollution Control Equipment or Process
Lurgi gasifier startup, preheat gases, and lock gas recovery	H <sub>2</sub> S, Nonmethane hydrocarbons	Flare
Gas purification system offgas, acid gas from ammonia production, gas liquor expansion gas	H <sub>2</sub> S	Stretford unit
Stretford unit offgases	Hydrocarbons, CO, H <sub>2</sub> S, mercaptans	Catalytic converter
Glycol regeneration	Hydrocarbons	Flare
Storage tanks containing naphtha	Nonmethane hydro- carbons and reduced sulfur compounds	Floating roof tanks
Storage tanks containing oil, phenol, tar, and gas liquor water	Nonmethane hydro- carbons, reduced sulfur compounds, and ammonia	Fixed roof tanks
Texaco gasifier startup offgases	H <sub>2</sub> S, hydrocarbons, mercaptans	Flare
Limestone and coal handling conveyors, storage buildings, trans- fer points, reclaim areas	Particulates	Enclosure with bag- house filter on venti- lation exhausts
Waste handling conveyors	Particulates	Enclosure
Solid waste storage piles	Particulates	Watering
Materials handling transfer points	Particulates	Telescopic chutes
Coal and coal fines reclaim	Particulates	Underground reclaim
Coal pile	Particulates	Grading, packing with crusting agents



Table 3.3-7 Concluded

Emission Source or Process	Controlled Pollutants	Pollution Control Equipment or Process
Coal pile traffic	Particulates	Chemical dust suppressants
Coal-fired boiler	SO <sub>2</sub>	Flue gas desulfurization system
Coal-fired boiler	Particulates	Electrostatic precipitator
Coal-fired boiler	NO <sub>x</sub>	Burner control and overfire air
General fugitive emissions from gasification plant	Hydrocarbons, CO, trace elements	Preventive maintenance and good housekeeping practices
Coal lock exhaust gases	Hydrocarbons, reduced sulfur gases	Incineration in boiler



Table 3.3-8

## SOLID WASTES FROM 300 MMSCFD GASIFICATION PLANT

Solid Wastes to Mine	Production Rates, tons/hour (dry)
Lurgi Gasifier Ash	54
Texaco Gasifier Slag	0.38
Precipitator Ash	13
Bottom Ash	3
FGD Sludge	5
Cooling Tower Sludge	Infrequent
Raw Water Treatment Sludge	0.23

Source: Data provided in 1974 by gasifying Amax coal from  
 the Big Hole Mine in Montana at Westfield, Scotland,  
 gasification plant.

Table 3-3-5

WATER TREATMENT PLANT

Production Rate, tons/day	Water to Mine
20	Large Gashier Ash
0.15	Yarns Gashier Ash
12	Yarns Gashier Ash
2	Small Ash
2	Small Ash
Interpret	Coaling Tower Sludge
0.12	Big Water Treatment Sludge

Table 3.3-9

## ROSEBUD COAL - GASIFIER ASH COMPOSITION

Constituent	Weight Percent	
	Fine Graded (2-10mm)	Coarse Graded (1/4 - 1-1/4")
Silicon Dioxide ( $\text{SiO}_2$ )	46.9	46.8
Alumina ( $\text{Al}_2\text{O}_3$ )	21.9	17.7
Iron Oxide ( $\text{Fe}_2\text{O}_3$ )	9.8	11.2
Calcium Oxide ( $\text{CaO}$ )	6.8	8.3
Magnesium Oxide ( $\text{MgO}$ )	4.2	3.9
Sulfur (as $\text{SO}_3$ )	1.0	1.7
Chloride ( $\text{Cl}$ )	<0.01	<0.01
Carbon ( $\text{C}$ )	4.8	6.5

Source: Tests performed in 1974 by gasifying Rosebud coal from Peabody Big Sky Mine in Montana at Westfield, Scotland, gasification plant.



would be used in the proposed plant. The main constituents are silica ( $\text{SiO}_2$ ), lime ( $\text{CaO}$ ), and alumina ( $\text{Al}_2\text{O}_3$ ).

The Texaco Gasifier produces a fused slag and fine soot, both composed of noncombustible materials. The feedstock to the Texaco gasifier would be mainly tars and oils produced from the Lurgi gasifier. The slag comes from the melting of coal ash that is a residue from very fine coal particles contained in the liquid feedstock.

Leaching tests performed on Lurgi gasifier ash from a test burn by Sasol One (Proprietary) Limited, and on Texaco slag from a test burn using Lurgi liquid feedstocks, are summarized in Tables 3.3-10 and 3.3-11; the results show the ash and slag to be classifiable as "nonhazardous" according to the RCRA Extraction Procedure.

Gasifier ash would be sluiced from the gasifiers to a dewatering facility, which would remove ash from the sluice water for loading onto the ash conveying system.

Boiler Bottom Ash. Boiler bottom ash is a vitrified (fused) inert residue resulting from combustion of coal. Bottom ash is usually quenched and crushed at the base of the boiler and, as a result, usually has a particle size equivalent to gravel. Table 3.3-12 shows the average composition of Rochelle coal ash. Boiler bottom ash is generally low in concentrations of the more volatile trace elements (arsenic, cadmium, molybdenum, lead, sulfur, and zinc) when compared with boiler precipitator ash (see above). The vitrified nature of bottom ash should render any trace elements present in the ash unavailable for leaching.

Bottom ash was obtained from a Wyoming steam generating utility burning a coal similar to the Rochelle coal. This ash was subjected

would be used in the proposed plant. The main constituents are silica (SiO<sub>2</sub>), iron (Fe), and alumina (Al<sub>2</sub>O<sub>3</sub>).

The Johnson Gasifier produces a liquid slag and fine ash, both of great economic value. The slag is the liquid portion of the gasifier. It would be mainly iron and also produced from the large gasifier. The slag comes from the melting of coal and that is a residue from very fine coal particles contained in the liquid slag.

Gasifying tests performed on large gasifiers and from a test by Daniel and (Proprietors) limited, and on Johnson Gas from a test have shown that liquid slag, as mentioned in Tables 3-3-10 and 3-3-11; the results show the ash and slag to be classifiable as "sintered" according to the BMA Extraction Procedure.

Gasifier ash would be mixed from the gasifier to a dewatering facility, which would remove ash from the sludge water for loading onto the ash conveying system.

Boiler Bottom Ash. Boiler bottom ash is a vitrified (fused) inert residue resulting from combustion of coal. Bottom ash is usually crushed and crushed at the base of the boiler and, as a result, usually has a particle size equivalent to gravel. Table 3-3-12 shows the average composition of Rockville coal ash. Boiler bottom ash is generally low in concentrations of the more volatile trace elements (arsenic, cadmium, molybdenum, lead, selenium, and zinc) when compared with boiler precipitated ash (see above). The vitrified nature of bottom ash should render any trace elements present in the ash not available for leaching.

Bottom ash was obtained from a Wyoming steam generating utility burning a coal similar to the Rockville coal. This ash was subjected

Table 3.3-10

RESULTS OF RCRA EP TOXICITY TESTING ON SOLID WASTES ROUTED TO THE INTERIM STORAGE AREA  
(mg/l)

Contaminant	RCRA <sup>a</sup> Limits	Lurgi <sup>b</sup> Ash	Texaco Slag	Bottom <sup>c</sup> Ash	Precipita- <sup>c</sup> tor Ash	Scrubber <sup>c</sup> Sludge	Codisposal <sup>d</sup> Mix
Arsenic	5.0	0.023/0.011	<.0003	0.003	0.048	<0.002	0.056
Barium	100.0	4.8/3.5	0.15	0.29	0.88	<0.053	0.31
Cadmium	1.0	<0.008/<0.008	<.03	<0.008	0.025	<0.008	<0.008
Chromium	5.0	0.012/0.012	<.02	<0.001	0.33	<0.001	0.098
Lead	5.0	0.003/<0.001	<.02	0.002	0.011	<0.001	0.005
Mercury	0.2	<0.0002/<.0002		<0.0002	<0.0002	<0.0002	<0.0002
Selenium	1.0	<0.003/0.006	<.004	<0.003	0.043	<0.003	0.044
Silver	5.0	<0.002/<0.002	<.06	<0.002	<0.002	<0.002	<0.002

<sup>a</sup> Federal Register , May 19, 1980, pp. 33127-33129.

<sup>b</sup> Toxicity testing was performed on the two samples of the gasifier ash from the Sasol One (Proprietary) Ltd. test burn.

<sup>c</sup> Toxicity testing was performed on these wastes collected at a Wyoming power plant burning coal similar in composition to the Rochelle coal.

<sup>d</sup> Codisposal mix #1: Gasifier Ash - 71.7% (Dry Weight)  
 Precipitator Ash - 17.6  
 Bottom Ash - 4.3  
 Scrubber Sludge - 6.4

3-45



Table 3.3-11

## RESULTS OF WATER QUALITY ANALYSIS ON NEUTRAL LEACHATE

Contaminants	Gasifier Ash	Texaco Slag	Bottom Ash	Precipita- tor Ash	Scrubber Sludge	Codisposal Mixture #1
Aluminum	46		15	9.0	0.16	<0.05
Boron	0.080		0.081	1.7	0.030	0.08
Beryllium	<0.0005		<0.0005	<0.0005	<0.0005	<0.0005
Calcium	100		77	280	660	450.
Cobalt	<0.006		<0.006	<0.006	<0.006	<0.006
Copper	<0.001		0.004	<0.001	0.017	<0.001
Iron	0.011		<0.008	<0.008	0.010	0.01
Potassium	1.2		0.65	1.5	2.4	2.1
Silicon	0.95		1.7	0.68	1.2	17
Manganese	<0.001		<0.001	<0.001	0.30	<0.001
Molybdenum	0.060		0.026	0.008	<0.002	0.62
Sodium	24.		9.4	14	37	28
Nickel	0.021		0.024	0.015	0.027	0.01
Antimony	0.06		<0.03	<0.03	<0.03	0.04
Titanium	<0.005		0.007	<0.005	0.018	<0.005
Thallium	<0.09		<0.09	<0.09	<0.09	<0.09
Vanadium	<0.003		0.065	<0.003	0.026	<0.003
Zinc	0.006		<0.003	<0.003	0.012	<0.003
TOC	1.7		2.1	14.1	2.1	3.7
Chloride	1.6		3.8	<1.0	10.8	1.42
Sulfate	<1.0		84.	<1.0	1200	910
Phenols	0.007		<0.005	0.008	0.005	0.005
Conductivity (uhmo/cm)	1270		461	2400	2120	1650
pH (Units)	11.6		10.9	11.9	7.46	11.1

3-46



Table 3.3-12

AVERAGE MINERAL ANALYSIS OF ROCHELLE COAL ASH  
(weight percent)

Constituent	
Silicon Dioxide ( $\text{SiO}_2$ )	31.6
Phosphorus Pentoxide ( $\text{P}_2\text{O}_5$ )	1.1
Ferric Oxide ( $\text{Fe}_2\text{O}_3$ )	5.8
Aluminum Oxide ( $\text{Al}_2\text{O}_3$ )	15.9
Titanium Dioxide ( $\text{TiO}_2$ )	1.1
Calcium Oxide ( $\text{CaO}$ )	24.9
Magnesium Oxide ( $\text{MgO}$ )	5.9
Sulfur Trioxide ( $\text{SO}_3$ )	10.9
Potassium Oxide ( $\text{K}_2\text{O}$ )	0.3
Sodium Oxide ( $\text{Na}_2\text{O}$ )	1.6
Undetermined	0.8
Total	100.0

Table 3.3-12

ANALYSIS OF MINERAL ANALYSIS OF MONTECAL COAL AND  
(Weight Percent)

Concentration	
21.8	Silicon Dioxide ( $SiO_2$ )
1.1	Phosphorus Pentoxide ( $P_2O_5$ )
1.8	Calcium Oxide ( $CaO$ )
12.9	Aluminum Oxide ( $Al_2O_3$ )
1.1	Titanium Dioxide ( $TiO_2$ )
12.9	Calcium Oxide ( $CaO$ )
2.9	Magnesium Oxide ( $MgO$ )
10.9	Sulfur Trioxide ( $SO_3$ )
0.2	Potassium Oxide ( $K_2O$ )
1.8	Sodium Oxide ( $Na_2O$ )
0.8	Unidentified
100.0	Total

to the RCRA Extraction Procedure. The results, presented in Table 3.3-10, show the ash to be classified as nonhazardous.

Precipitator Ash. The ash entrained in flue gas after coal firing is called fly ash. Once the fly ash has been removed from the flue using electrostatic precipitators, it is referred to as precipitator ash. Fly ash is a fine-grained vitrified material 10-100 microns in diameter. Fly ash produced at the WyCoalGas plant would have approximately the same gross mineral composition as the bottom ash, which is shown in Table 3.3-12. Because of its small particle size, fly ash would be more susceptible than either gasifier or bottom ash to leaching of trace metals. Nevertheless, results in Table 3.3-10 of a RCRA extraction leaching test performed on fly ash from the Wyoming power plant show that fly ash would be classified as nonhazardous under RCRA.

Flue Gas Desulfurization Sludge. Sulfur dioxide would be removed from boiler flue gas in spray tower absorbers utilizing limestone as a reagent. A gypsum sludge would be produced, composed of primary calcium sulfate ( $\text{CaSO}_4 \cdot 2\text{H}_2\text{O}$ ) with small amounts of calcium sulfite ( $\text{CaSO}_3 \cdot 1/2\text{H}_2\text{O}$ ) and calcium carbonate ( $\text{CaCO}_3$ ). This sludge would be classified as nonhazardous under the RCRA requirement as shown in Table 3.3-10. The sludge would be dewatered and loaded onto the ash conveying system. The dewatering system would consist of thickeners (or clarifiers) followed by mechanical dewatering equipment.

Codisposal Mixture. Laboratory tests were conducted to estimate the disposal properties of the ash and scrubber sludge as a codisposal mixture. The mixture contained the following wastes in their estimated production ratios:

to the HMA Extraction Procedure. The results, presented in Table 1.3-10, show the ash to be classified as noncombustion.

Extraction Test. The ash contained in flow gas after coal firing is called fly ash. When the fly ash has been removed from the fine being extracted precipitates, it is referred to as precipitate ash. Fly ash is a fine-grained vitrified material 10-100 microns in diameter. Fly ash produced at the Wyandotte plant would have approximately the same gross mineral composition as the bottom ash, which is shown in Table 1.3-11. Because of its small particle size, fly ash would be more susceptible than either bottom ash or leaching of trace metals. Nevertheless, results in Table 1.3-10 of a HMA extraction leaching test performed on fly ash from the Wyoming power plant show that fly ash would be classified as noncombustion under HMA.

Flow Gas Condensation Sludge. Solids sludge would be removed from bottom line gas in spray tower absorbers utilizing lime sludge as a reagent. A system sludge would be produced, composed of primary calcium sulfate ( $\text{CaSO}_4 \cdot 2\text{H}_2\text{O}$ ) with small amounts of calcium sulfate ( $\text{CaSO}_4 \cdot 1/2\text{H}_2\text{O}$ ) and calcium carbonate ( $\text{CaCO}_3$ ). This sludge would be classified as noncombustion under the HMA requirements as shown in Table 1.3-10. The sludge would be dewatered and landfilled. The ash conveying system. The dewatering system would consist of thickener (or clarifier) followed by mechanical dewatering equipment.

Condensate Sludge. Laboratory tests were conducted to estimate the disposal properties of the ash and scrubber sludge as a condensation mixture. The mixture contained the following values in their estimated production values:

- 1) Gasifier ash - 71.7% (dry weight)
- 2) Precipitator ash - 17.6%
- 3) Bottom ash - 4.3%
- 4) Scrubber sludge - 6.4%

The results of RCRA toxicity testing performed on the codisposal mixture are presented in Table 3.3-10. As shown, the concentrations of the eight elements in the codisposal extract are well below the RCRA limits.

In general, the initial handling properties of the codisposal mixture would be similar to those of moist soil. Once compacted in the interim storage area, the mixture would harden, due to hydration reactions similar to those occurring in portland cement. The wide range in particle sizes within the codisposal mixture would result in a material with poor permeability, roughly that of silts or silt-and-clay mixtures.

Raw Water Treatment Sludge. These wastes include all waste from the raw water treatment process. Approximately 37 tpd of raw water treatment sludge at 15 percent solids would be produced; of this, 75 percent of the solid weight would be from those solids, primarily calcium salts, brought into the process as dissolved solids and removed from the water. The remaining portion of the solids would be spent treatment chemicals. Table 3.3-13 lists the composition of water treatment sludge. Such wastes are generally considered non-hazardous. The raw water treatment sludge would be used in the Lurgi gasifier and boiler bottom ash sluicing systems. Therefore, it would ultimately be disposed of with the coal ash.

Cooling Tower Sludge. Airborne soil and dust from the plant area could become trapped in the cooling towers. Infrequent disposal



Table 3.3-13

WATER TREATMENT SLUDGE COMPOSITION  
(weight percent)

Soda Ash $\text{Na}_2\text{CO}_3$	89
Magnesium Hydroxide, $\text{Mg}(\text{OH})_2$	9
Silica Oxide	<u>2</u>
TOTAL	100.0

Source: Solid Waste Conceptual Plan for WyCoalGas  
Gasification Facility, 27 February 1981.

Table 1.3-11

WATER TREATMENT SLUDGE COMPOSITION  
(weight percent)

55	Solids and $H_2O$
5	Magnesium Hydroxide, $Mg(OH)_2$
2	Silica Oxide
100.0	TOTAL

Source: Solid Waste Management Plan for Hydrogen  
Gasification Facility, 21 February 1981.

(once every one to five years) of this material would be required. No compositional data are available. However, the material should be nonhazardous under RCRA. The cooling tower sludge would be codisposed with the coal ash.

### Waste Facilities

Ash Conveying System. The ash conveying system would consist of a series of enclosed conveyors and transfer points designed to transport solid wastes from the gasifier and bottom ash dewatering facility, the FGD sludge dewatering facility, and the fly ash conditioning area to either a rail car loading facility or an interim storage area.

The rail car loading facility would consist of a storage silo and a 100 ton weigh bin. The conveyed wastes would be loaded into the silo, which would feed the weigh bin. The weigh bin would be designed to discharge enough ash and sludge to fill one 100-ton railroad car per bin unloading. The ash would be hauled to the mine for burial, using rail cars designated especially for this purpose. At a waste cleanout area adjacent to the loading facility, ash which had dried and vitrified in these cars during previous trips to the mine, and was therefore not dislodged at the mine, would be loosened and broken up for easier handling using jackhammers or other means.

Wastes not directly loaded into rail cars would be stored at the on-site interim storage area. The conveyed wastes would be unloaded onto a 3000-ton loadout pile. Waste reclaimed from the interim storage area would be loaded into two 100-ton reclaim hoppers. The reclaim hoppers would feed two reclaim conveyors which would load the ash back onto the main conveying system for transport to the rail car loading facility. The reclaim system would be located underground.

(once every one to five years) at this material would be required. No compositional data are available. However, the material should be non-hazardous under RCRA. The cooling tower sludge would be discharged with the tail gas.

### Waste Facility

The existing system. The ash conveying system would consist of a series of vertical conveyors and transfer points designed to transport solid waste from the gasifier and boiler and dusting facilities, the RB storage dusting facility, and the fly ash conditioning unit to either a rail car loading facility or an interim storage area.

The rail car loading facility would consist of a storage silo and a 100-ton weigh bin. The conveyed waste would be loaded into the silo, which would feed the weigh bin. The weigh bin would be designed to discharge enough ash and sludge to fill one 100-ton railroad car per bin unloading. The ash would be loaded to the silo for burial, using rail cars designated especially for this purpose. As a waste stream, ash is subject to the loading facility, and which had dust and situated in these cases during previous trips to the silo, and was therefore not discharged at the silo, would be loaded and broken up for easier handling using jaw crushers or other means.

Waste not directly loaded into rail cars would be stored at the on-site interim storage area. The conveyed waste would be unloaded onto a 3000-ton loadout pile. Waste reclaimed from the interim storage area would be loaded into two 100-ton reclaim hoppers. The reclaim hoppers would feed two reclaim conveyors which would load the ash back onto the main conveying system for transport to the rail car loading facility. The reclaim system would be located underground.

Interim Solid Waste Storage. The interim solid waste storage would be used to store ash and solid waste during the winter months of each year when it cannot be transported to the mine. It would also be used for storage during start-up of the plant for a period of 18 months, until such time as the mine can accept it.

Ash and solid waste would be handled by front-end loaders and/or dump trucks which would pick it up from the stockpile. It would be removed from the storage area with the same equipment, and transported back to a reclaim hopper on the conveyor system for loading on to rail cars to the mine.

The area would hold 600,000 tons of ash and sludge, with an assumed density of 70 lbs/cubic foot; this capacity is based on the WyCoalGas estimate of the ash generated during the 18 months of start-up. The area would be 1,400 feet long and 300 feet wide. The 600,000 tons storage capacity would have a 15-foot depth of basin, and a storage pile height not exceeding 20 feet above finished grade. The material is assumed to be semi-dry, and would be stacked with 3:1 side slopes.

The stored material, with a sludge content, tends to act like cement. It is assumed that heavy earth moving equipment and front end loaders would be capable of breaking up and removing the ash at the end of the 18 month storage period.

A 15-inch-thick soil cement slab would be provided for the floor and side slopes of the ash storage site; this would be capable of withstanding 45,000 pound wheel loads of dump trucks or front end loaders.

Interim Solid Waste Storage. The interim solid waste storage would be used to store ash and solid waste during the winter months of each year when it cannot be transported to the mine. It would also be used for storage during start-up of the plant for a period of 15 months, until such time as the mine can accept it.

Ash and solid waste would be handled by front-end loaders and dump trucks which would pick it up from the storage. It would be removed from the storage area with the same equipment, and transported back to a reclamation project on the conveyor system for loading on to rail cars to the mine.

The area would hold 800,000 tons of ash and sledge, with an assumed density of 70 lbs/cubic foot. This capacity is based on the Wycolec's estimate of the ash generated during the 15 months of start-up. The area would be 1,400 feet long and 300 feet wide. The 800,000 tons storage capacity would have a 15-foot depth of basin, and a storage pile height not exceeding 15 feet above finished grade. The material is assumed to be sandy, and would be stacked with 3:1 side slopes.

The stored material, with a sledge conveyor, leads to not like any other. It is assumed that heavy earth moving equipment and front end loaders would be capable of breaking up and removing the ash at the end of the 15 month storage period.

A 15-inch-dia. well cement slab would be provided for the floor and side slopes of the ash storage area. This would be capable of withstanding 45,000 pound wheel loads of heavy trucks or tractors and loaders.

The interim solid waste storage area would be sloped to drain at the far end from the stockpile. A drainage system would be furnished which would deliver all contaminated run-off to the materials handling storm water pond north of the railroad loop.

Emergency Ash Pond. The Emergency Ash Pond would be used only in the event of failure of the mechanical systems (dewatering, screens, ash conveyors) which dewater the ash and convey it to the interim solid waste storage area. Gasifier ash and boiler bottom ash would be sluiced into the pond from the sluice-way system when the gates to the dewatering facility (normally open) are closed. FGD sludge would also be dumped into the pond if the ash handling conveyor system failed. The pond would receive the waste materials and would act as an ash settling basin until the mechanical equipment could be put back into service. A pump house would be located on the north side of the pond to provide circulation of water to the sluiceway systems. When the mechanical equipment is back in service, the pond would be drained and the ash removed, by front end loaders and/or dump trucks, to the interim solid waste storage area.

The pond would be sized to provide 10 to 20 days capacity of gasifier ash, bottom ash, and FGD sludge, assuming a total discharge of 75 tons per hour. Pond dimensions would be:

Bottom area (approx)	2 acres
Depth	20 feet
Depth at pump house	25 feet
Assumed depth of settled ash	8 feet.

A reinforced concrete slab 12 inches thick would be provided on the bottom and side slopes of the pond, designed to take a 45,000 pound wheel load for a front-end loader or a 75-ton dump truck. Side slopes would be 1 1/2:1.



## MATERIAL BALANCE

On-site Sanitary Landfill. A sanitary landfill would be used for disposal of refuse, including lumber, concrete, piping, and other inert construction materials, as well as garbage from the construction camp. Approximately 750 tons of refuse would be generated annually during plant operations, assuming an average of five pounds for each of the 1,196 people on-site during peak operation. During construction, the refuse generated would range from 17 to 160 tons per year as construction peaks.

## Hazardous Drum Storage

The drum storage facility would store hazardous and nonhazardous wastes in drums, in a covered 120 feet wide x 100 feet long pre-engineered building with a concrete foundation. The building would be enclosed on three sides. The east side would be open with a 14-foot wide dock extending across the opening; the dock and ramps at both ends would be curbed and have a catch basin for spills. Inside, the foundation would slope to the center of the building. Designated storage sections, each sized to hold 192 55-gallon drums, would be elevated 12 inches, with aisles between containing gutters, drains, and sumps for collecting spillage.

Following is a list of types of waste that would be stored, and the maximum number of 55 gallon drums to be stored in each designated area:

• Spent shift catalyst	960 drums
• Spent methanation catalyst	960 drums
• Zinc oxide	24 drums
• Laboratory waste	72 drums
• Halogenated waste	24 drums
• Tank farm spillage	384 drums

On-site Facilities A sanitary landfill would be used for disposal of refuse, including paper, concrete, piping, and other inert construction materials, as well as garbage from the construction camp. Approximately 150 tons of refuse would be generated annually during plant operations, amounting to an average of five trucks per week of the 1,175 people on-site during peak operation. During construction, the refuse generated would range from 15 to 150 tons per year as construction begins.

Wastewater Treatment

The storm sewage facility would store wastewater and nonhazardous wastes in drums. In a typical 120 foot wide x 100 foot long pre-engineered building with a concrete foundation. The building would be equipped on three sides. The east side would be open with a 14-foot wide track extending across the opening; the west end ramp at both ends would be closed and have a catch basin for spills. Inside, the foundation would slope to the center of the building. Reinforced concrete columns, each sized to hold 192 55-gallon drums, would be spaced 12 inches, with aisles between containing gutters, drains, and ramps for collecting effluage.

Following is a list of types of waste that would be stored, and the maximum number of 55 gallon drums to be stored in each designated area:

Spent acid catalyst	250 drums
Spent inorganic catalyst	250 drums
Spent oil	25 drums
Spent organic waste	75 drums
Spent water	25 drums
Spent lime effluage	100 drums

## MATERIAL BALANCE

The overall material balance of the proposed plant is shown in Table 3.3-14.

Table 3.3-15 lists the outputs from the Lurgi and Texaco processes. Those Lurgi liquids identified as Texaco process feedstocks would produce additional synthetic pipeline gas, and three tons per day each of additional ammonia and sulfur. All ammonia and sulfur would be distributed by existing railroad common carriers.

Operation of the plant would consume 84,000 gallons/year of gasoline and 134,000 gallons/year of diesel fuel.

## CONSTRUCTION

Construction Procedures

The gasification plant would be constructed in two stages, each capable of producing 150 MMSCFD of SPG. Stage I construction would start in 1983 with completion in 1986. Stage II construction would start in 1986 with completion in 1988. The total duration for construction would be 63 months, which includes 6 months pre-construction activity for temporary facilities and site grading.

The initial construction effort would be devoted to grading the entire site to specified elevations, constructing the temporary onsite work camp and facilities, and drilling two wells to supply 366,000 gallons of water per day for construction and for the work camp. The well locations are shown in Figure 3.3-2. The work camp is described below.

After site grading has been in progress for six months, work would begin on the foundations for the Phase I permanent buildings and the tankage. All foundations would be constructed of reinforced

MATERIAL BALANCE

The overall material balance of the proposed plant is shown in

Table 3.3-14.

Table 3.3-15 lists the output from the large and medium processes. These large inputs identified as process products would produce additional synthetic pipeline gas, and three times per day each of additional ammonia and sulfur. All ammonia and sulfur would be distributed by existing railroad common carriers.

Operation of the plant would consume 54,000 gallons/year of gasoil and 134,000 gallons/year of diesel fuel.

CONSTRUCTION

Construction Procedures

The construction plant would be constructed in two stages, each capable of producing 150 MWD of 300. Stage I construction would start in 1965 with completion in 1966. Stage II construction would start in 1966 with completion in 1968. The total duration for construction would be 6 months, which includes 6 months pre-construction activity for temporary facilities and site grading.

The initial construction effort would be devoted to grading the entire site to specified elevations, constructing the temporary drainage work area and facilities, and drilling two wells to supply 300,000 gallons of water per day for construction and for the work camp. The well locations are shown in Figure 3.3-1. The work camp is described below.

After site grading has been in progress for six months, work would begin on the foundations for the Phase I permanent buildings and the tanks. All foundations would be constructed of reinforced

TABLE 3.3-14

## OVERALL MATERIAL BALANCE, 300 MMSCFD PLANT

Inputs, tons/day		Outputs, tons/day	
Coal	32,600	6,538	SPG
Air	90,160	68	Sulfur
Water	23,160	108	Ammonia
TOTAL	145,920	22,500	Nitrogen to Atmosphere
		69,330	Desulfurized Boiler Flue Gas
		1,274	Gasifier Ash (Dry)
		431	Boiler Ash (Dry)
		28,630	Catalytic Converter Tail Gas
		2,070	Coal Fines to Sales
		13,200	Water Evaporated in Cooling Tower
		4,180	Water to Pond Evaporation, Waste Solids and Flue Gas Desulfurization Sludge, etc.
TOTAL 145,920			

TABLE 1.1-14

## OVERALL MATERIAL BALANCE, 500 MHDGP PLANT

Inputs, tons/day		Outputs, tons/day	
Coal	11,800	6,338	STE
Air	65,140	48	Exhaust
Water	12,140	108	Ammonia
TOTAL	145,920	22,500	Hydrogen to Ammonia
		69,130	Desulfurized Boiler Flue Gas
		1,774	Gasifier Ash (Dry)
		431	Boiler Ash (Dry)
		28,430	Catalytic Converter Tail Gas
		1,070	Coal Slime to Boiler
		13,200	Water Evaporated in Cooling Tower
		4,180	Water to Pond Evaporation, Waste Solids and Flue Gas Desulfurization Sludge, etc.
TOTAL 145,920			

TABLE 3.3-15

## LURGI AND TEXACO GASIFICATION OUTPUT

Outputs	Short Tons/Day	Barrels/Day
Elemental Sulfur	68	-
Anhydrous Ammonia	109	-
Excess Coal Fines	2,070	-
Phenol <sup>a</sup>	183	946
Naphtha <sup>a</sup>	189	1,402
Tar Oils <sup>a</sup>	621	3,978
Tar <sup>a</sup>	437	2,330

<sup>a</sup>These Lurgi process liquid outputs would be gasified using the Texaco process; the resulting additional synthetic pipeline gas has already been included in the plant's 300 MMSCFD output figure.

Exterior materials and colors for the physical structures at the plant site would be selected to blend with the surrounding landscape as much as possible. Non-reflective materials and low gloss paints would be used, in colors equivalent to Pittsburgh Paint & Glass "Sage-brush Over-Green," Sherwin Williams "Sandstone". The visual contrast between plant and surroundings would be reduced with landscaping techniques such as selective use of contours, earth berms, and plantings along the "rebel" edge of the plant site (along approximately 3 miles of State Highway 59 north of County Road 35). Large rocks unearthed during plant construction and grading, as well as fertile topsoil, would be stockpiled and used in landscaping. Plantings would include natural species, such as sagebrush, Ponderosa Pine, Gray's Juniper, and various grasses.



concrete. Concrete work would be in accordance with Standard Specifications of the American Concrete Institute (ACI-38-71). All steel structures would be designed, fabricated, and erected in accordance with Standard Specifications for Structural Steel for buildings as adopted by the American Institute of Steel Construction. Structures would be designed on the basis of the American National Standard for structures in this geographical location (A.S.A. A58. 1-1972) for a 50-year mean recurrence interval for snow and wind.

Three months after the start of Phase I foundation work, sufficient permanent plant material would be onsite to allow the start of Phase I mechanical work. Mechanical work for Phase I would take 39 months to complete. Fourteen months prior to the mechanical completion of Phase I, foundations and underground piping and electrical work for Phase II would begin. Three months after start of Phase II foundation work, Phase II mechanical work would start. Phase II mechanical work would take 37 months.

Exterior materials and colors for the physical structures at the plant site would be selected to blend with the surrounding landscape as much as possible. Non-reflective materials and low gloss paints would be used, in colors equivalent to Pittsburgh Paint & Glass "Sagebrush Grey-Green" #PPG33 and Wilko "Sandstone". The visual contrast between plant and surroundings would be reduced with landscaping techniques such as selective use of contours, earth berms, and plantings along the "public" edge of the plant site (along approximately 3 miles of State Highway 59 north of County Road 55). Large rocks unearthed during plant construction and grading, as well as fertile topsoil, would be stockpiled and used in landscaping. Plantings would include natural species, such as sagebrush, Ponderosa Pine, Pinyon Juniper, and prairie grasses.



The equipment list shown in Table 3.3-16 includes all major equipment that would be used during the construction of the gasification plant. The amount of equipment shown represents the maximum requirements. Jobsite durations would vary according to the equipment type and need. It is planned that all equipment would work five days per week, ten hours per day while on the jobsite.

#### On-site Construction Worker Camp and Facilities

Camp. A \_\_\_\_\_-acre temporary construction camp would be established at the plant site, consisting of dormitory units for single workers and a recreational vehicle (RV) park for singles and couples without children; centralized food and other services; and recreational facilities. The camp would be located in the southeast corner of the plant site, as shown in Figure 3.3-10, approximately 1-1/2 miles from the construction area. Provision would be made for up to 1,200 dormitory rooms and 600 RV spaces; design would allow for adjustment of this balance, and possible expansion. Camp design is shown in Figure 3.3-11.

Camp Water Supply. Water for all camp uses would be drawn from two wells at the plant site (see Figure 3.3-2); treated to potable quality and disinfected at the plant site; and pumped to the camp. Camp water demands (domestic and irrigation) would average 276,000 gpd; an additional 90,000 gpd would be used at the construction site. A storage capacity of 516,000 gallons would be provided for daily demand and firefighting needs.

Camp Waste Water Collection and Treatment. The camp's waste water collection system would conform to requirements of the State of Wyoming. Waste water would flow by gravity to an activated sludge treatment plant located as shown in Figure 3.3-2. Water would be treated to secondary standards (30 mg/l suspended solids, 30 mg/l



TABLE 3.3-16

## MAJOR EQUIPMENT REQUIREMENTS FOR GASIFICATION PLANT CONSTRUCTION

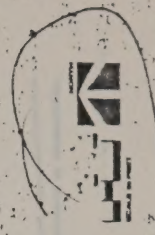
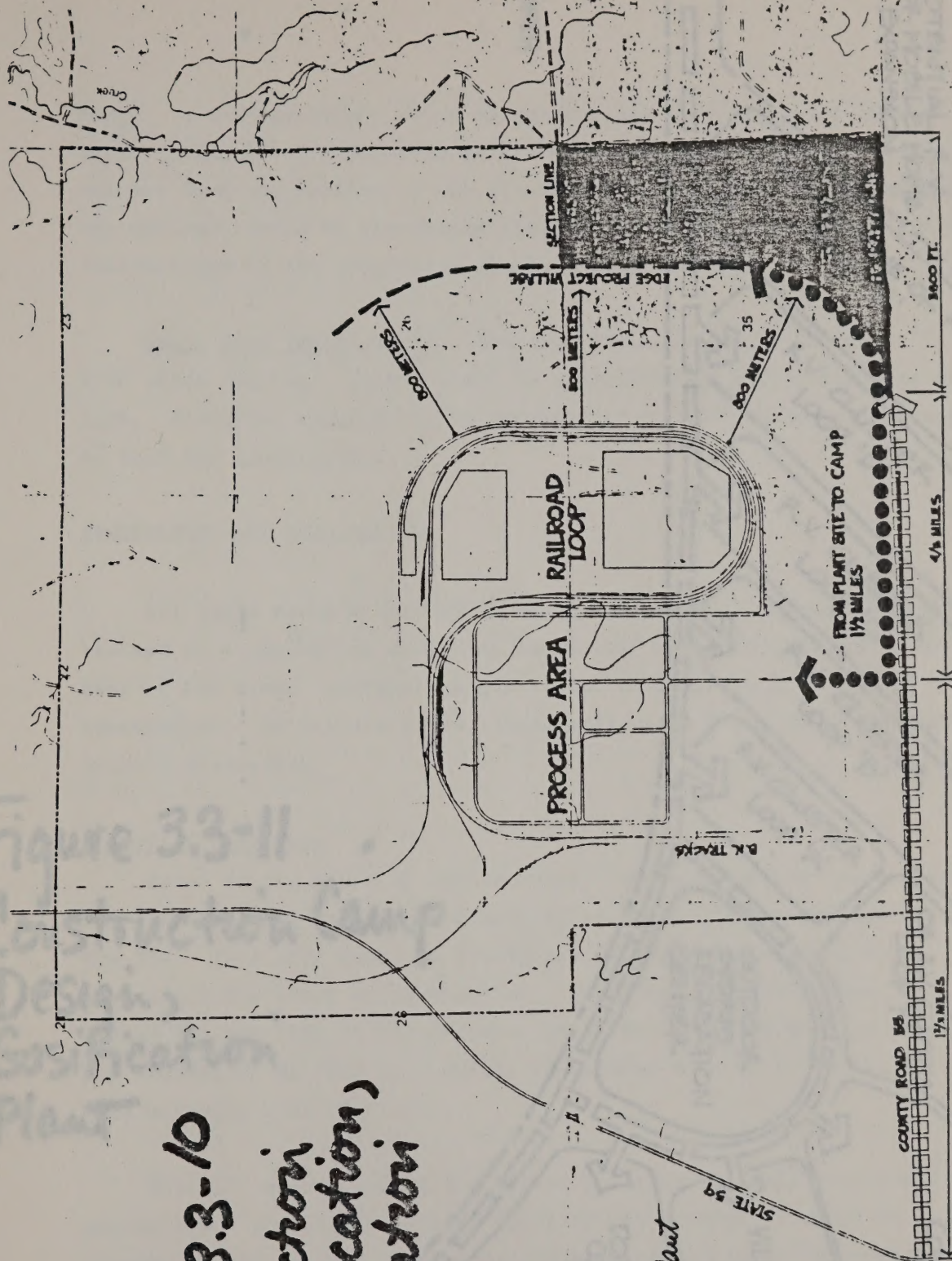
Office Facilities	<ul style="list-style-type: none"> <li>4 - Office trailers - 12' x 60'<sup>a</sup></li> <li>3 - First aid trailers - 8' x 32'</li> <li>4 - Comfort trailers - 8' x 32'</li> <li>4 - Change trailers - 10' x 60'<sup>a</sup></li> <li>3 - Timekeeper trailers - 10' x 35'</li> </ul>
Job Site Transportation	<ul style="list-style-type: none"> <li>1 - Sedan - 4D medium</li> <li>1 - Station wagon - heavy duty</li> <li>2 - Sedans - 4D heavy duty</li> <li>60 - Pick-ups - 1/2 ton</li> <li>3 - Pick-ups - 3/4 ton</li> <li>10 - Stake body trucks - 3/4 ton</li> <li>1 - Van - 1/2 ton suburban</li> <li>1 - Ambulance - 3/4 ton</li> </ul>
Site work and foundations	<ul style="list-style-type: none"> <li>15 - Earthmovers - 20 CY</li> <li>6 - Dozers - D9W</li> <li>2 - Dozers - D7</li> <li>2 - Dozers - D4</li> <li>10 - Dump trucks - 4 ton</li> <li>3 - sheepsfoot rollers - 20 ton</li> <li>2 - vibratory rollers - 25,000 lb</li> <li>40 - Plate tampers - 30" x 36"</li> <li>5 - Loaders/backhoes - 1 CY</li> <li>4 - Front-end loaders - 2 1/4 CY</li> <li>3 - Crawler/Excavators - 1 1/2 CY</li> <li>2 - Motor graders</li> <li>4 - Concrete buckets - 2 CY</li> <li>4 - Concrete buckets - 1 CY</li> </ul>
Mechanical Installation	<ul style="list-style-type: none"> <li>10 - Scissors scaffolds - 25' 1000 lb</li> <li>10 - Cherry pickers - 12 ton</li> <li>5 - Cherry pickers - 18 ton</li> <li>10 - Rough terrain cherry pickers - 30 ton</li> <li>1 - Rough terrain crane - 65 ton</li> <li>1 - Rough terrain crane - 80 ton</li> <li>1 - Truck crane - 80 ton</li> <li>2 - Crawler cranes - 100 ton</li> <li>2 - Crawler cranes - 155 ton</li> <li>2 - Crawler cranes - 200 ton</li> <li>1 - 4100 ringer - 36'</li> <li>1 - Tower frame - 270' - 55 ton</li> <li>5 - Air tuggers - 18" long drum</li> <li>10 - Welders - 200 amp DC</li> <li>30 - 8 - Pac welders - 200 Amp</li> <li>5 - Portable welders - 200 Amp</li> <li>3 - Portable welders - 300 Amp</li> </ul>
Material Handling & Distribution	<ul style="list-style-type: none"> <li>4 - Tractors - 4 speed gas</li> <li>4 - Flatbed trucks - 2 ton</li> <li>10 - Flatbed dump trucks - 2 ton</li> <li>5 - Farm wagons - 8 ton</li> <li>2 - Platform trailers - 30 ton</li> <li>1 - Lowbed trailer - 30 ton</li> <li>3 - Forklifts - 2500 lb</li> <li>1 - Forklift - 10,000 lb</li> </ul>

<sup>a</sup>To be used only until temporary facilities are constructed.



**Figure 3.3-10**  
**Construction**  
**Camp Location,**  
**Gasification**  
**Plant.**

Add:  
 - treatment plant



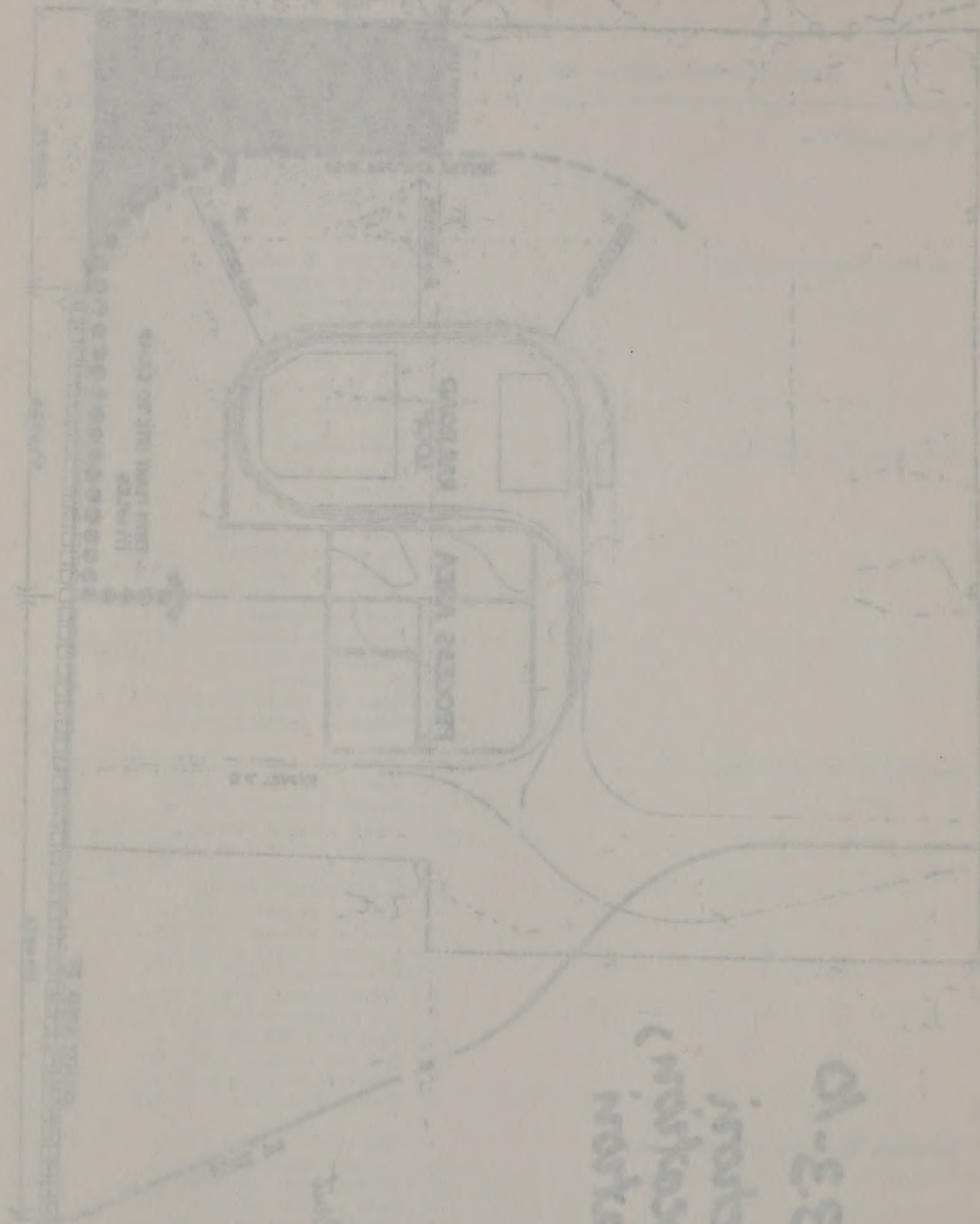
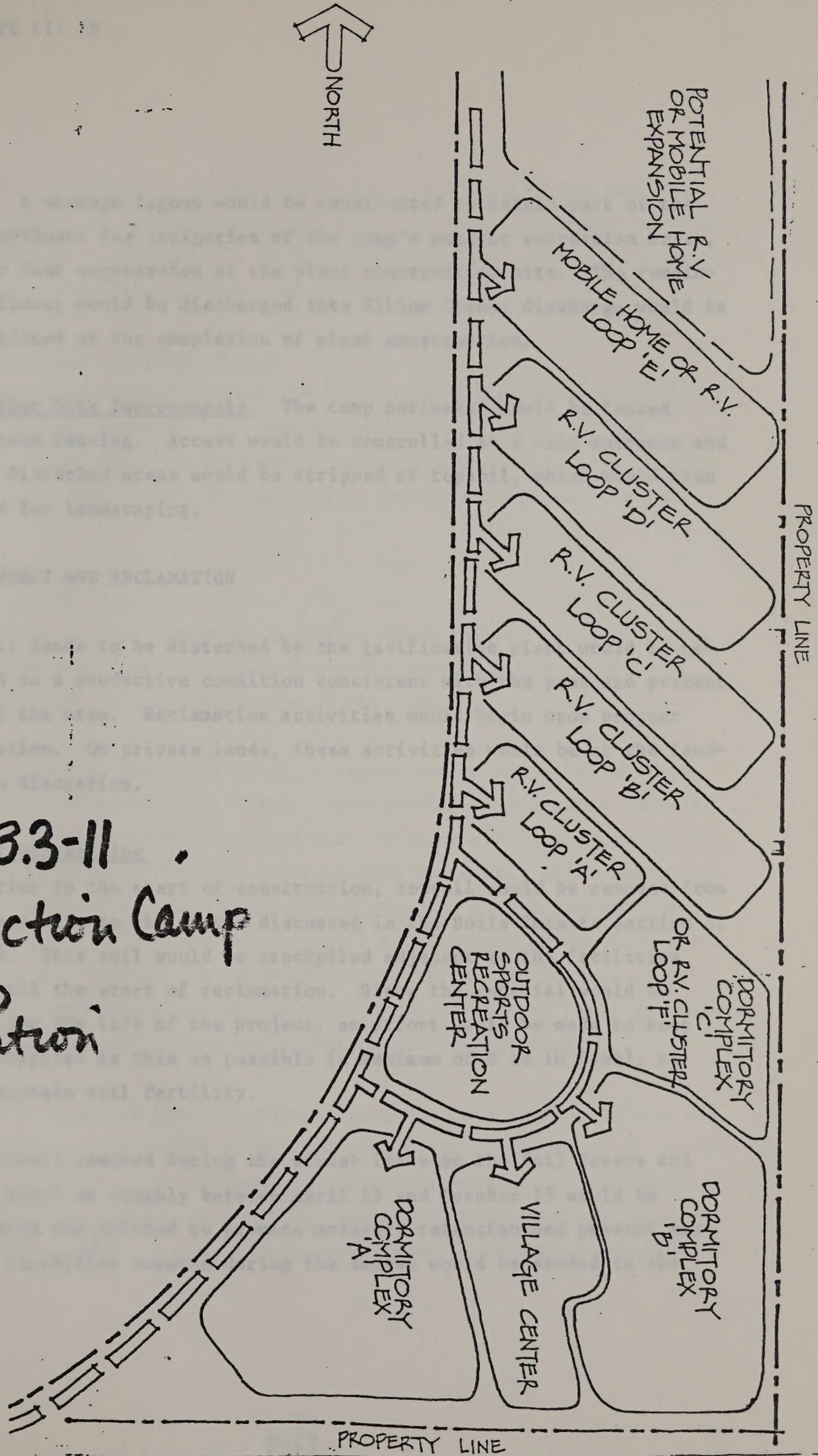
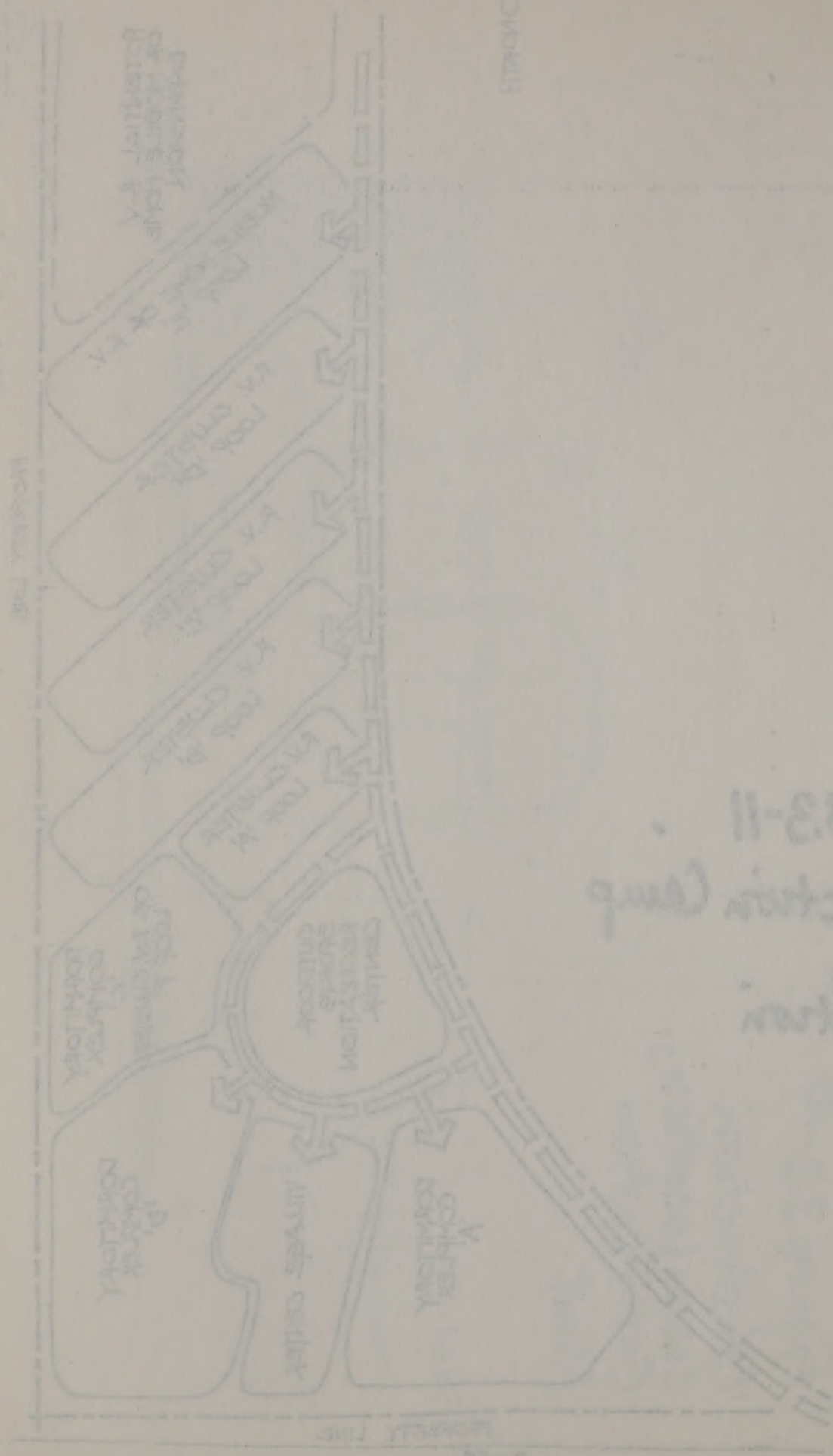


Fig. 33-10  
 1. Fuel System  
 2. Electrical System  
 3. Water Pump

Figure 3.3-11  
Construction Camp  
Design,  
Gasification  
Plant



Plant  
 Gasification  
 Design  
 Construction Camp  
 Figure 3.3-11



BOD<sub>5</sub>). A storage lagoon would be constructed to retain part of the plant effluent for irrigation of the camp's outdoor recreation areas, and for dust suppression at the plant construction site. The remaining effluent would be discharged into Willow Creek; discharge would be discontinued at the completion of plant construction.

Other Site Improvements. The camp perimeter would be fenced with stock fencing. Access would be controlled at a main entrance and gate. Disturbed areas would be stripped of topsoil, which would then be used for landscaping.

#### ABANDONMENT AND RECLAMATION

All lands to be disturbed by the gasification plant would be reclaimed to a productive condition consistent with the past and present uses of the area. Reclamation activities would begin upon project termination. On private lands, these activities would be at the landowner's discretion.

#### Topsoil Stockpiling

Prior to the start of construction, topsoil would be removed from the plant site to the depths discussed in the Soils Impacts section of the EIS. This soil would be stockpiled adjacent to the facilities area until the start of reclamation. Since the material would be stored for the life of the project, an effort would be made to keep the stockpiles as thin as possible (a maximum of 8 to 10 feet), to help maintain soil fertility.

Topsoil removed during the winter (between the fall freeze and spring thaw) or roughly between April 15 and October 15 would be stockpiled and mulched to promote moisture retention and prevent erosion. Stockpiles created during the summer would be seeded in the



fall after October 15; stockpiles created during the winter would be seeded after the spring thaw up to April 15. Topsoil removed between the spring thaw and April 15 or between October 15 and the fall freeze would be stockpiled, mulched, and seeded.

#### Decommissioning and Dismantling

Following project termination, the gasification plant would be dismantled and removed. All foundations would be broken up and buried. After water in the process waste pond has evaporated, the residue and liner would be removed to a permanent, approved disposal site.

#### Topsoil Replacement

Disturbed areas would be graded to approximately pre-project contours. Topsoil from the stockpiles would then be spread uniformly over the sites to a minimum depth of one foot.

Maintaining good soil tilth is recognized as essential to establishing a permanent plant cover. Consequently, precautions would be taken to prevent undue soil compaction during topsoil replacement, and to avoid movement of topsoil material when it is wet. Since watering would be used as a normal dust control practice during reclamation activities, it is unlikely that topsoil would become so dry that its structure is destroyed during movement. However, in the event that the soil becomes very dry during the summer, sufficient water would be added during topsoil spreading operations to prevent damage.

It is expected that the subsoil material on the plant site would be compacted. Where this material is sufficiently compacted to significantly restrict root development and normal movement of soil moisture from the surface, it would be loosened by deep ripping. Ripping would also be done on all slopes greater than 15 degrees. Depending

fall after October 15; stockpiles treated during the winter would be seeded after the spring thaw up to April 15. Topsoil removed between the spring thaw and April 15 or between October 15 and the fall freeze would be stockpiled, washed, and seeded.

#### Recommendations and Limitations

Following project termination, the gasification plant would be dismantled and removed. All foundations would be broken up and buried. After water in the process waste pond has evaporated, the residue and liner would be removed in a permanent, approved disposal site.

#### Topsoil Reclamation

Disturbed areas would be graded to approximately pre-project contour. Topsoil from the stockpiles would then be spread uniformly over the sites to a minimum depth of one foot.

Maintaining good soil which is recognized as essential to water filtering a permanent plant cover. Consequently, precautions would be taken to prevent undue soil compaction during topsoil replacement, and to avoid movement of topsoil material when it is wet. Where watering would be used as a normal dust control practice during reclamation activities, it is unlikely that topsoil would become so dry that its structure is destroyed during movement. However, in the event that the soil becomes very dry during the summer, sufficient water would be added during topsoil spreading operations to prevent drying.

It is expected that the subsoil material on the plant site would be compacted. Where this material is sufficiently compacted to significantly restrict root development and normal movement of soil water from the surface, it would be loosened by deep ripping. Ripping would also be done on all slopes greater than 15 degrees. Depending

on conditions and materials at each location, the ripping would extend 18 to 24 inches into the zone immediately below the replaced topsoil. This operation would be done after the topsoil is spread to ensure an adequate bond between the topsoil and the subsoil. Ripping would not be done when the soil is wet because better shattering results when the material is relatively dry.

#### Mulching

The topsoil to be used in reclamation is predominantly sandy loam in texture. Since wind erosion can be severe in this type of soil, mulching would be done on topsoil stockpiles and reclaimed areas prior to seeding. The type of mulch and its rate of application would depend on availability of material and the condition of the soil. However, mulch would generally consist of small grain straw and would most often be applied at a rate of one to two tons/acre. The mulch would be spread over the topsoil and then anchored with a crimping disc. Discing would be done at right angles to slopes.

#### Seeding

The seed mixture applied to the stockpiles and reclaimed areas would be as shown in Table 3.3-17. Whenever possible, planting would be done with a drill. Seed would be planted at an average depth of 1/2 inch, and a maximum depth of one inch. Broadcast seeding would be used only on areas too small for drill seeding equipment; broadcast seeding rates would be double the rates given above. Harrowing, brush dragging, chaining, or hand raking would be used to cover the seed with soil. To ensure optimum plant establishment, seeded areas would be protected by fencing or similar approved animal control techniques for at least two complete growing seasons.

Since precipitation is quite low in eastern Wyoming, the time of seeding is important. As a general rule, planting would be done in

on conditions and materials at each location, the timing would extend 18 to 24 inches into the zone immediately below the topsoil layer. This operation would be done after the topsoil is spread in place and adequate bond between the topsoil and the subsoil. Spacing would be done when the soil is wet because better shearing results when the material is relatively dry.

### Matching

The topsoil to be used in restoration is predominantly sandy loam in texture. When such erosion can be covered in this type of soil, matching would be done on topsoil structure and retained areas prior to seeding. The type of seed and its rate of application would be based on availability of material and the condition of the soil. However, seed would generally consist of small grain straw and would most often be applied at a rate of one to two tons/acre. The seed would be applied over the topsoil and then anchored with a releasing disc. Discing would be done at right angles to slopes.

### Seeding

The seed mixture applied to the structure and retained areas would be as shown in Table 2-3-1. Whenever possible, planting would be done with a drill. Seed would be planted at an average depth of 1 1/2 inch, and a maximum depth of one inch. Broadcast seeding would be used only on areas too small for drill seeding equipment; broadcast seeding rates would be double the rates given above. Fertilizing, brush dragging, chaining, or hand raking would be used to cover the seed with soil. To ensure optimum plant establishment, seeded areas would be protected by fencing or similar approved animal control techniques for at least two complete growing seasons.

Blank precipitation is quite low in western Wyoming, the time of seeding is important. As a general rule, planting would be done in

Table 3.3-17

STOCKPILE AND RECLAMATION SEED MIXTURE,  
GASIFICATION PLANT

Species <sup>a</sup>	Pounds Pure Live Seed/Acre
Critina thickspike wheatgrass ( <u>Agropyron</u> <u>dasystachyum</u> )	4
Western wheatgrass ( <u>A . smithii</u> )	4
Indian ricegrass ( <u>Oryzopsis</u> <u>hymenoides</u> )	2
TOTAL	10

<sup>a</sup>To help insure adaptation, seed used for the reclamation program would be obtained from plants originating within a band approximately 300 miles north to 200 miles south of the project area.

#### Irrigation

Irrigation is not projected for the reclamation program. Moisture in greater than normal amounts could promote the establishment of weedy or otherwise undesirable plant species at the expense of desirable perennial grasses. In addition, irrigation could create an oasis in this generally arid region, which would tend to attract thousands of large numbers of domestic livestock and wildlife. This could result in overgrazing, which would damage or destroy newly established vegetation.

Table 1-1-17

STOCKING AND RECLAMATION NEEDS  
- ESTIMATION TABLE -

Species	Number of Acres
<i>Citrus chinensis</i> (var. <i>chinensis</i> )	4
<i>Western chinensis</i> (var. <i>chinensis</i> )	4
<i>Indian chinensis</i> (var. <i>chinensis</i> )	2
<i>Chinese chinensis</i> (var. <i>chinensis</i> )	—
TOTAL	10

To help insure adaptation, seed used for the reclamation program would be obtained from plants existing within a band approximately 300 miles south of 400 miles south of the project area.

the late fall, after October 15, to ensure that the maximum amount of moisture is present for germination and seedling establishment. If this were not feasible, it would be done in early spring, prior to April 15.

#### Herbicides

It is not anticipated that herbicides would be needed for control of undesirable broadleaf plants during the early stages of plant establishment. If they are necessary, however, control measures would be taken in accordance with manufacturer's recommendations and existing state and federal regulations. Once the desired native plant species become established, weed control would probably be unnecessary.

#### Fertilization

The soils in eastern Wyoming are relatively fertile, and soil supplements would probably not be required prior to seeding. However, fertilization within one to two years of germination might be necessary to maintain plant vigor. Soil tests would be conducted on all topsoil prior to seeding in order to determine the need for fertilization, the optimum fertilizer mixture, and the appropriate time for application.

#### Irrigation

Irrigation is not projected for the reclamation program. Moisture in greater than normal amounts could promote the establishment of weedy or otherwise undesirable plant species at the expense of desirable perennial grasses. In addition, irrigation could create an oasis in this generally arid region, which would tend to attract abnormally large numbers of domestic livestock and wildlife. This could result in overgrazing, which would damage or destroy newly established vegetation.

The late fall, after October 15, no longer fits the pattern of moisture is present for germination and seedling establishment. If this were not feasible, it would be best to apply water prior to April 15.

### Barbicide

It is not anticipated that herbicides would be needed for control of undesirable broadleaf plants during the early stages of plant establishment. If they are necessary, however, control measures should be taken in accordance with manufacturer's recommendations and existing state and federal regulations. Once the desired native plant species become established, weed control would probably be unnecessary.

### Fertilization

The soils in eastern Wyoming are relatively fertile, and this equipment would probably not be required prior to seeding. However, fertilization within one to two years of germination might be necessary to maintain plant vigor. Soil tests would be conducted on all topsoil prior to seeding in order to determine the need for fertilization, the optimum fertilizer mixture, and the appropriate time for application.

### Tractor

Tractor is not projected for the reclamation program. However, there is greater than normal amount of work to be done in the establishment of shrub or otherwise undesirable plant species at the expense of desirable perennial species. In addition, tractor would be used to provide in this generally arid region, which would tend to attract sporadically large numbers of domestic livestock and wildlife. This would result in overgrazing, which would damage or destroy newly established vegetation.

### 3.4 ROCHELLE COAL MINE

#### 3.4.1 General Description

##### Introduction

At full production, the proposed gasification plant would require approximately 10.2 million tons of subbituminous coal per year. However, coal mining and handling would result in the production of some fines that cannot be used in the Lurgi gasification process (refer to section 3.3). As a result a total of approximately 10.8 million tons of coal must be supplied to the plant each year.

Coal for the project would be furnished entirely from the proposed Rochelle Mine, a surface mine to be located in southeastern Campbell County, approximately 40 miles north of the plant and 68 road miles south of Gillette; see Figure 3.4-1. The mine, to be permitted and managed jointly by Pan Eastern Coal Company and Powder River Coal Company (as described in Section 1.1) and to be operated by Powder River Coal Company, would supply the gasification plant; should the plant not be constructed, the coal from this mine would be sold to other markets. Ash generated in the gasification process would be returned to the mine for burial.

The Rochelle Mine permit boundary is shown in Figure 3.4-2. The boundary encompasses 6,660 acres; of this, a total of 5,210 acres would be disturbed by mining and associated activities. Most of the land within the permit boundary is covered by Federal Coal Lease No. W-0321779; Table 3.4-1 lists the areas covered by this lease. The remaining area is privately owned. Figure 3.4-3 depicts surface ownership in the area, and Figure 3.4-4 shows coal ownership and lessees.

## 2.4 ROCKWELL COAL MINE

### 2.4.1 General Description

#### Introduction

At full production, the proposed Rockwell plant would produce approximately 10.5 million tons of bituminous coal per year. However, coal mining and handling would result in the production of some fines that cannot be used in the large gasification process under section 2.3. As a result a total of approximately 10.5 million tons of coal must be supplied to the plant each year.

Coal for the project would be furnished entirely from the proposed Rockwell Mine, a surface mine to be located in southeastern Campbell County, approximately 60 miles north of the plant and 60 miles south of Gillette and Figure 2.4-1. The mine is to be owned and managed jointly by San Francisco Coal Company and Powder River Coal Company (as described in Section 1.1) and is to be operated by Powder River Coal Company, which would supply the gasification plant; should the plant not be constructed, the coal from this mine would be sold to other markets. Ash generated in the gasification process would be returned to the mine for burial.

The Rockwell Mine permit boundary is shown in Figure 2.4-1. The boundary encompasses 6,666 acres of land, a total of 2,710 acres would be disturbed by mining and associated activities. Most of the land within the permit boundary is covered by Federal Coal Lease No. W-032175; Table 2.4-1 lists the areas covered by this lease. The remaining area is privately owned. Figure 2.4-2 depicts surface ownership in the area, and Figure 2.4-3 shows coal ownership and location.

3-69

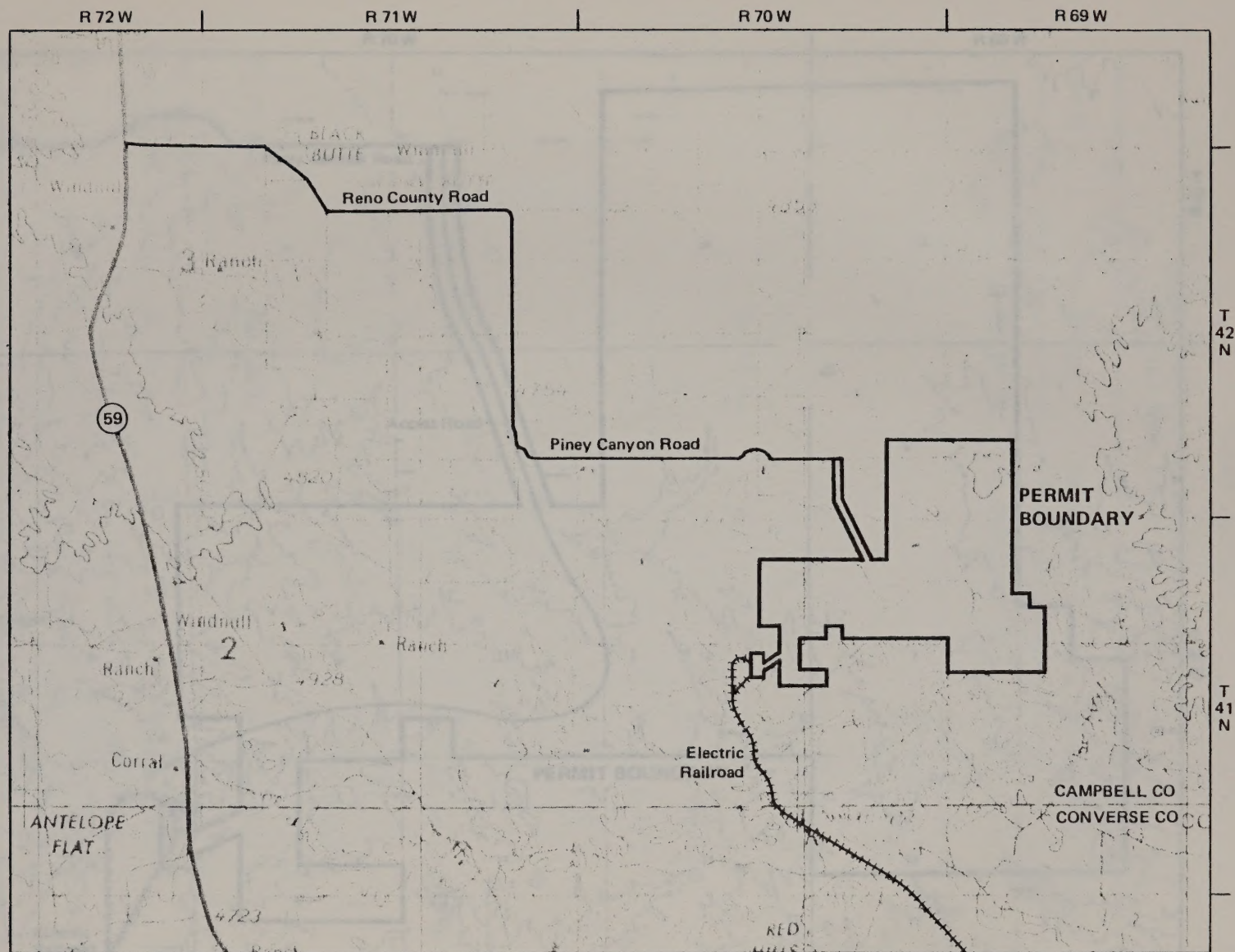
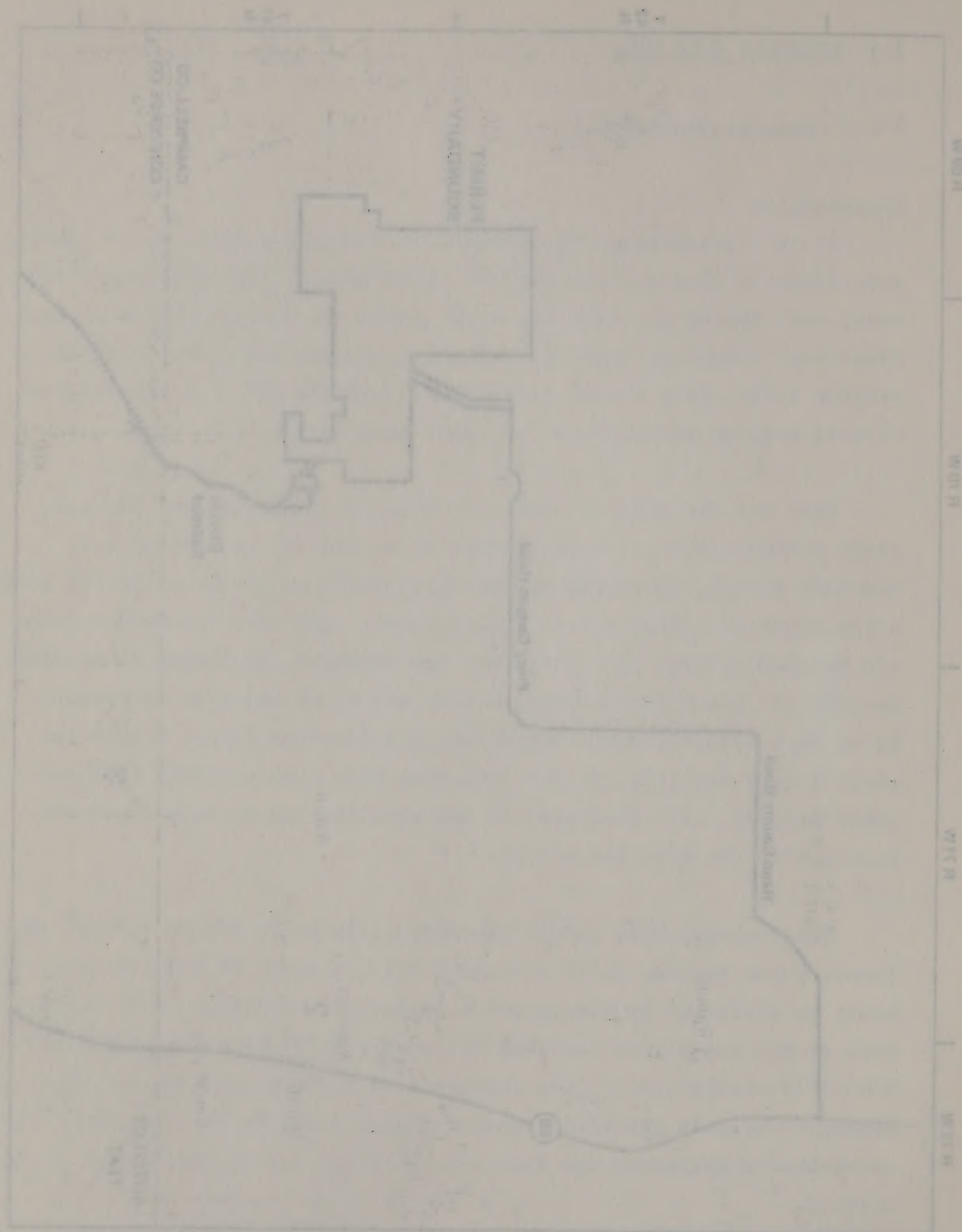


Figure 3.4-1  
ROCHELLE MINE LOCATION

# MOCHETTE MINE LOCATION Sheet 2 of 2



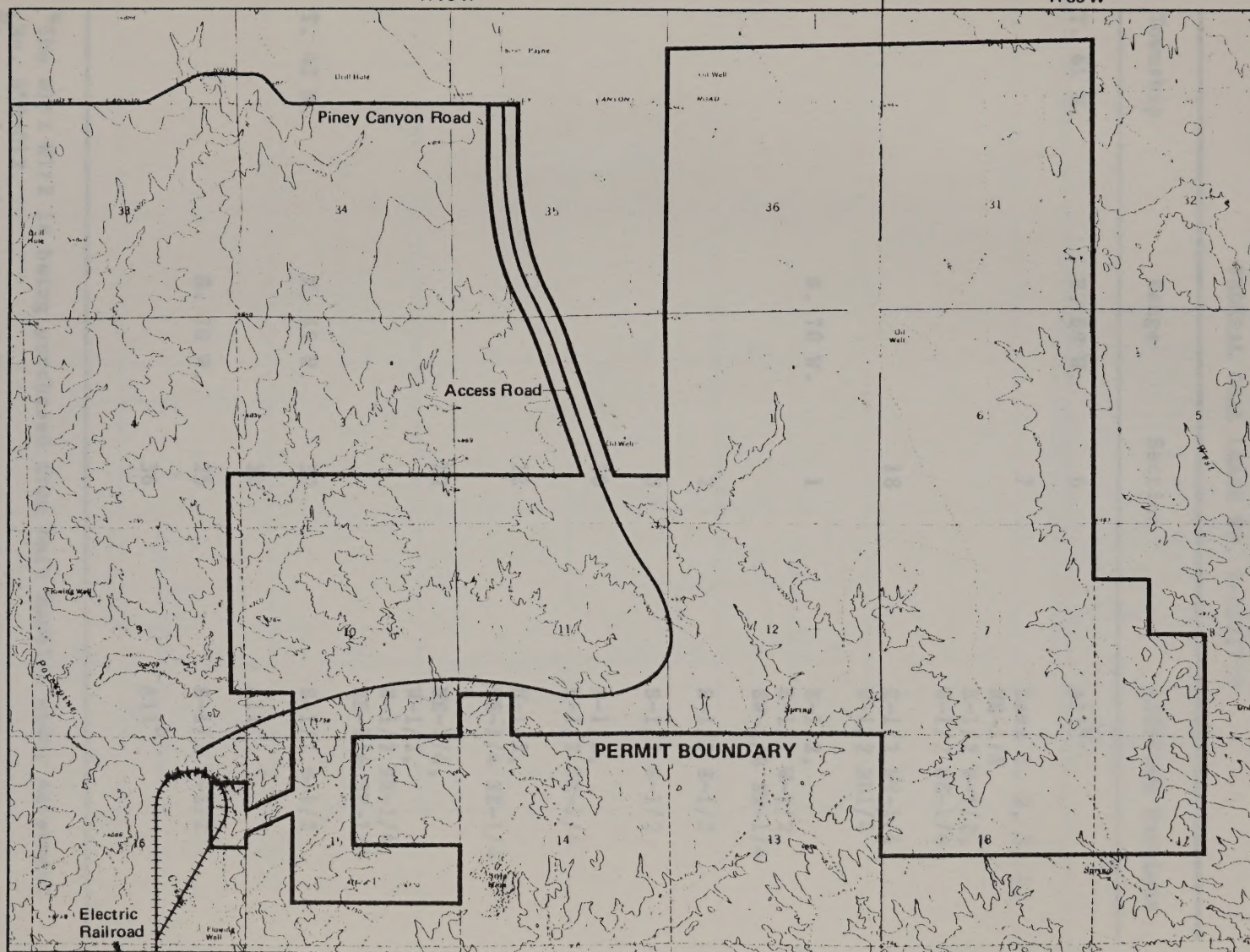


Figure 3.4-2  
ROCHELLE MINE PERMIT BOUNDARY

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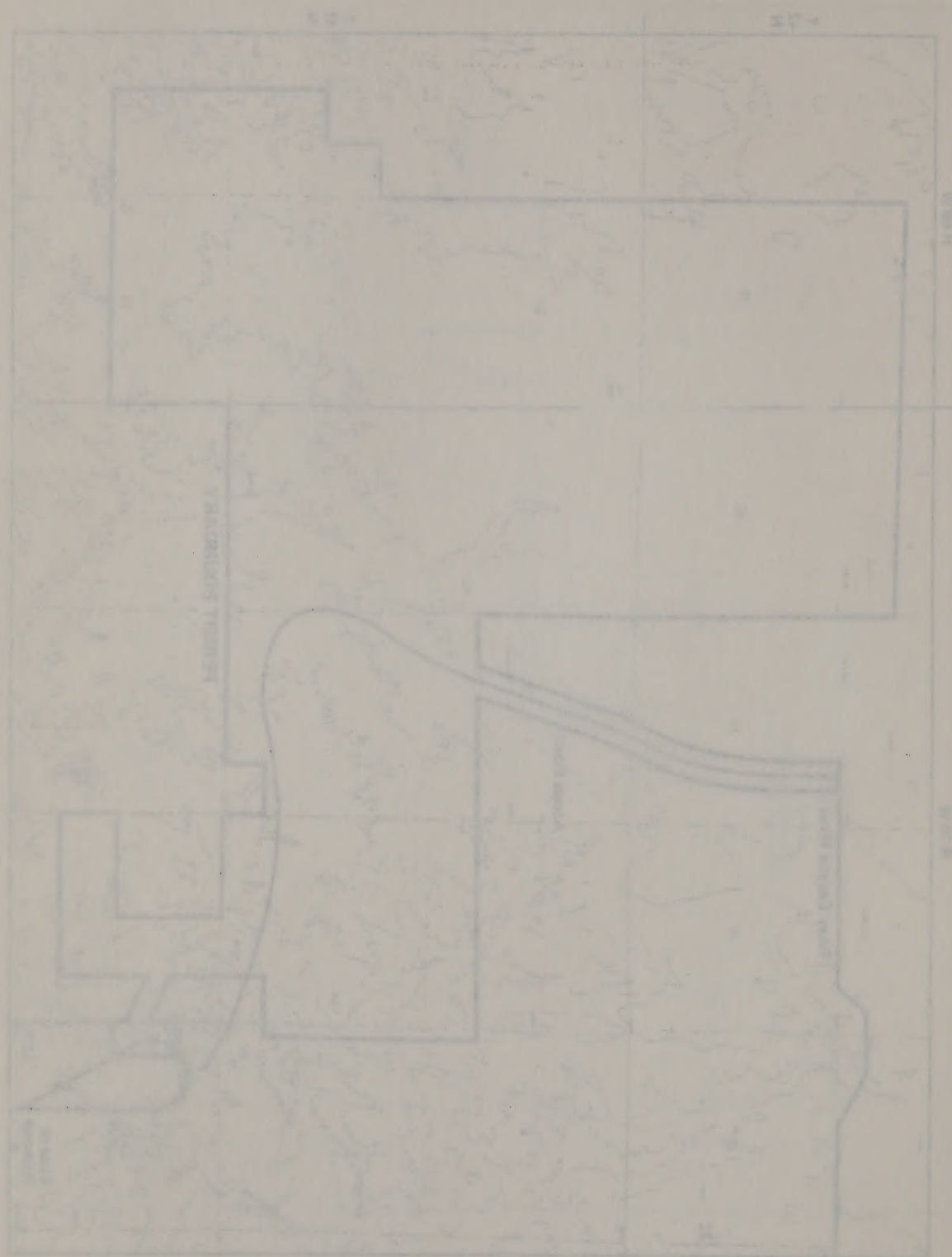


TABLE 3.4-1

AREA AFFECTED BY ROCHELLE COAL MINE  
FEDERAL COAL LEASE NO. W-0321779

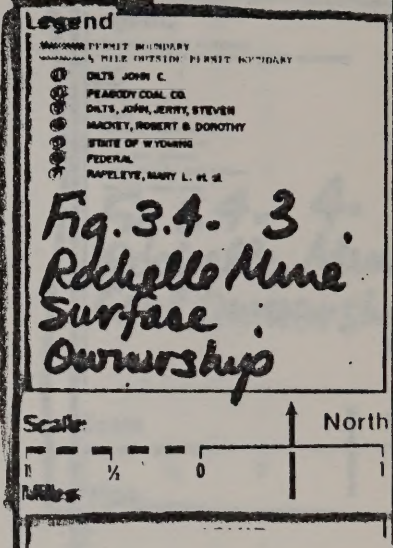
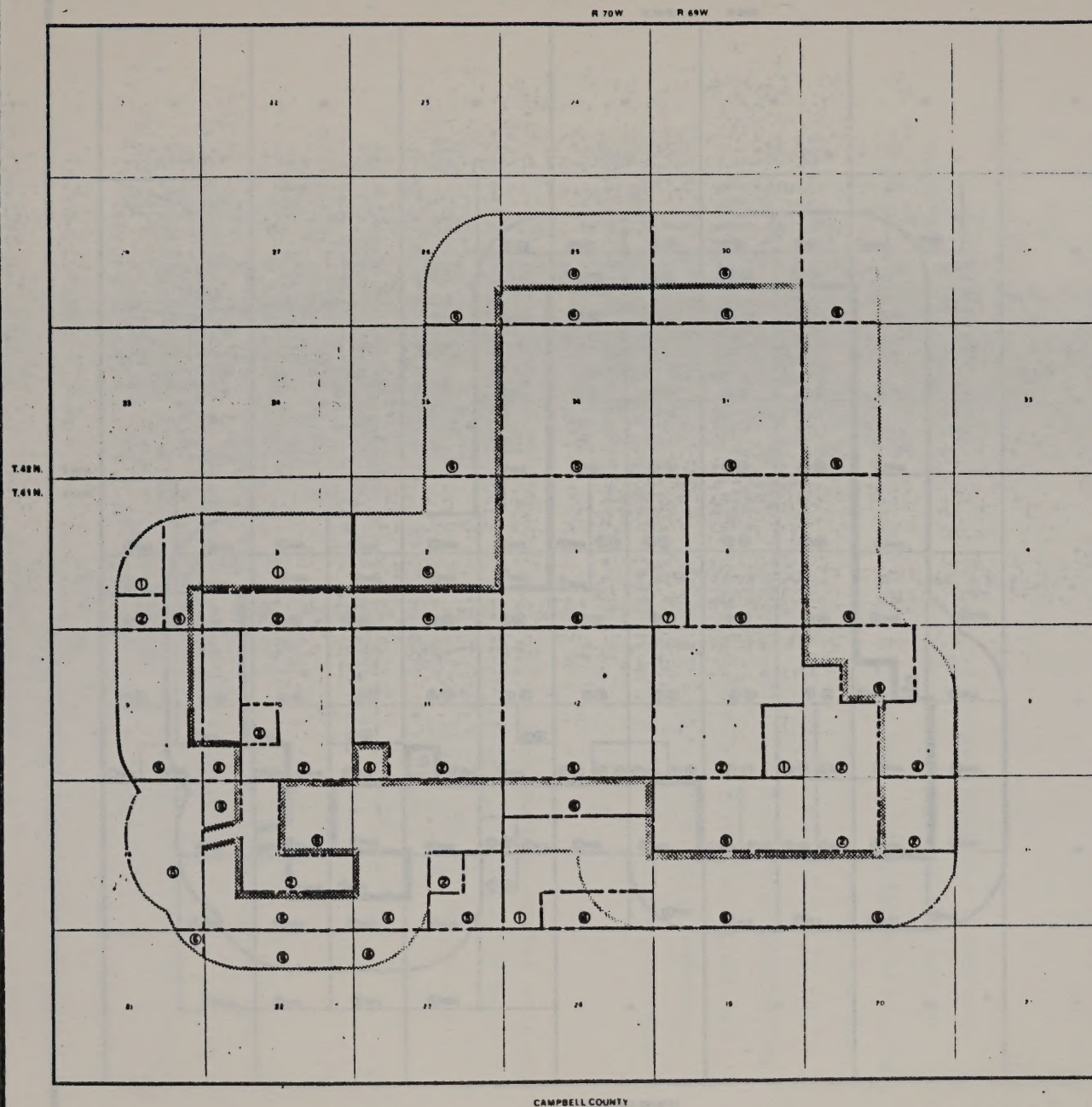
Township	Range	Section	Affected Portions
T. 41 N.	R. 69 W.	6	All <sup>a</sup>
		7	Lots 1, 2, 3, 4, NE-1/4, E-1/2 W-1/2, W-1/2 SE-1/4
		18	E-1/2 NW-1/4, W-1/2 NE-1/4
	R. 70 W.	1	E-1/2, E-1/2 W-1/2, SW-1/4 SW-1/4
		2	S-1/2 S-1/2
		3	S-1/2 S-1/2
		10	N-1/2, N-1/2 SE-1/4
		11	N-1/2, NE-1/4 SE-1/4
		12	NE-1/4, W-1/2, N-1/2 SE-1/4, SE-1/4 SE-1/4
T. 42 N.	R. 69 W.	30	S-1/2 S-1/2
		31	All
	R. 70 W.	25	S-1/2 S-1/2
		36	All <sup>b</sup>

<sup>a</sup>The W1/2 W1/2 is being purchased from Mary Rapelye under Agreement No. 455-012.

<sup>b</sup>Leased from the state of Wyoming under Lease No. 0-26749.

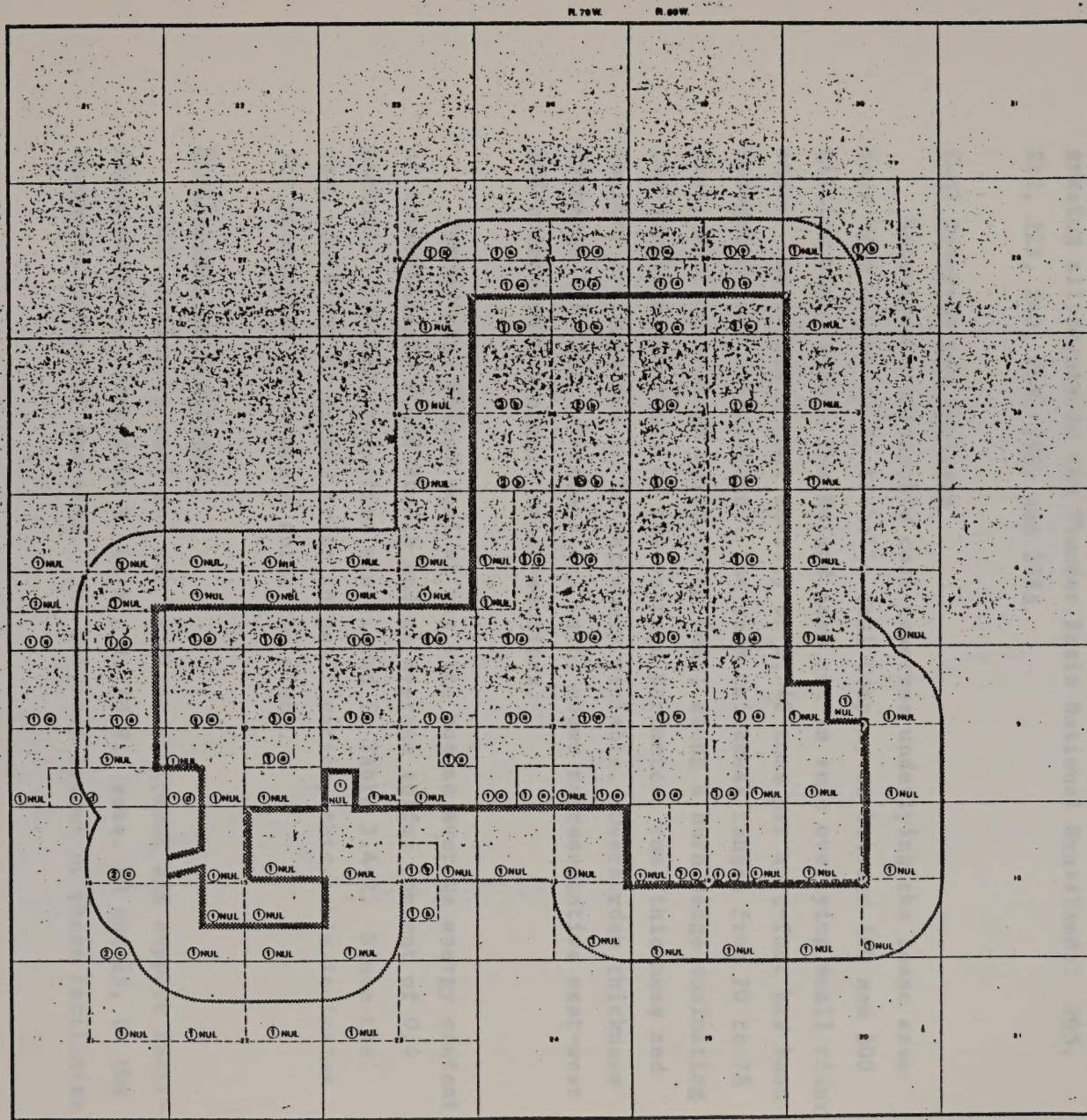


3-72





3-73

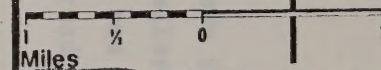


### Legend

- PERMIT BOUNDARY
- 1 MILE OUTSIDE PERMIT BOUNDARY
- OWNER
- ① USA
- ② WYOMING
- LESSOR
- A MICHELLE COAL COMPANY
- B PEABODY COAL COMPANY
- C BARR COAL COMPANY
- D NORTH ANTELOPE COAL COMPANY
- NUL - NOT UNDER LEASE

**Fig. 3.4- 4**  
**Rockelle Mine**  
**Coal Ownership**

Scale





Primary vehicular access to the site, as shown in Fig. 3.4-1, would be from State Highway 59, approximately 8 miles south of Reno Junction; east along the Reno County Road; south and east on Piney Canyon Road; and southeast along a proposed new road section.

The permit boundary would include part or all of the following grazing allotments in the Thunder Basin National Grasslands: 205, 212, 223, 240, 268, 298, and 298A.

#### Coal Reserves and Analysis

Recoverable strippable coal reserves underlying the lease area have been estimated by Rochelle Coal Company at between 400 and 500 million tons, within the Roland seam and in some overlying small rider seams. An in-place coal density of 1,740 tons per acre-foot has been assumed in all estimations. The seam thickness ranges from 20 to 78 feet, with an average value of 66 feet; along a burn wedge dominating the southern and parts of the eastern perimeter, coal thickness and quality are expected to be extremely variable. Overburden thickness averages 134 feet. Figure 3.4-5 (a,b) shows representative east-west and north-south geologic cross-sections.

Run-of-mine Roland coal at the site has an average energy content of approximately 8,500 Btu/lb and an average sulfur content of 0.4 percent. Further properties are listed in Table 3.4-2. Since the coal would not be washed prior to gasification, this table indicates its properties as it would enter the plant.

#### Facilities and Equipment

All stationary coal and ash handling equipment and support facilities would be located in T. 41 N., R. 70 W., secs. 10 and 15, in the southwest corner of the site. The proposed layout of these facilities



**ROCHELLE COAL CO.**  
**ROCHELLE MINE**  
 12015 E. 10th Ave.  
 DENVER, CO 80230

**LEGEND**

**SCALE**

**GEOLOGIC CROSS SECTION**  
**SECTION A-A'**

DESIGN BY P. Brown  
 DRAWN BY S. Weber  
 CHECKED BY S. Scott

REVISIONS DATE 3-1-80  
 SHEET 1 of 1  
 Dwg. No. 1000

WEST EAST

Roland seam

Fig. 3.4-5(a). Geologic Cross Section 1

Station  
New



Don Johnson (20) 2-4-5-6-7

3-76

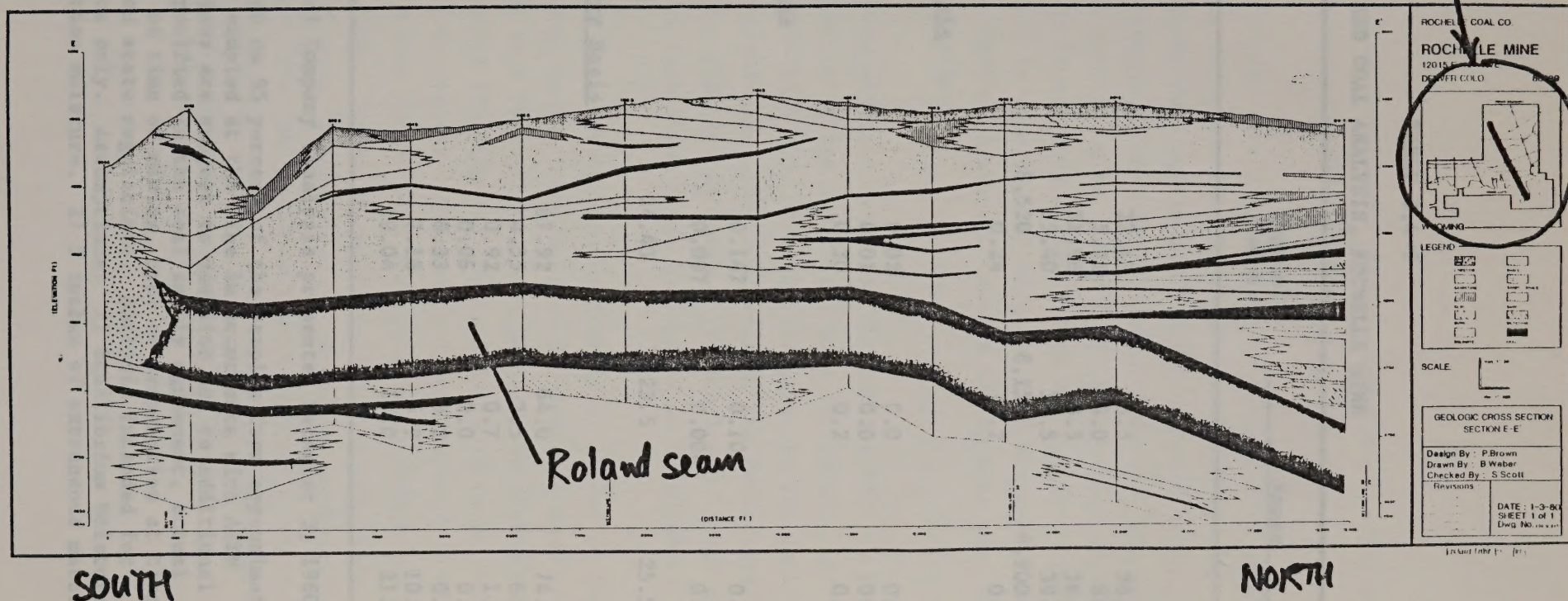


Fig.3.4-5(b). Geologic Cross Section 2

Shale  
mass



DATE	TIME	LOCATION



MTW02

MTW01

mass

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3-54

TABLE 3.4-2

## ROLAND COAL ANALYSIS, ROCHELLE MINE

Proximate Analysis	Typical Value	Range	
(As Received)			
Moisture	27.43	25.5	30.5
Ash	5.21	4.0	8.0
Volatile	31.96	28.5	36.5
Fixed Carbon	35.40	31.5	39.5
Btu/lb	8,520	8,150	8,900
Sulfur	0.24	0.2	0.6
<u>Sulfur Forms    Dry Basis</u>			
Pyritic	0.02	0.0	0.1
Sulfate	0.01	0.0	0.1
Organic	0.30	0.2	0.5
<u>Water Soluble Alkalies</u>			
Na <sub>2</sub> O	0.147	0.100	0.200
K <sub>2</sub> O	0.007	0.000	0.025
<u>Equilibrium Moisture</u>	24.43	23.5	25.5
<u>Ultimate Analysis    Dry Basis</u>			
Carbon	67.92	64.0	74.0
Hydrogen	4.55	3.5	6.0
Nitrogen	0.92	0.7	1.2
Chlorine	0.06	0.0	0.15
Sulfur	0.33	0.2	0.8
Ash	7.18	5.9	10.4
Oxygen	19.04	16.0	21.0

Source: Rochelle Coal Company (analysis presented December 2, 1980).

Indicated ranges based on 95 percent of the samples from approximately 10,000 ton shipments sampled at the mine in accordance with ASTM Standards. All analyses are subject to revision due to additional coring, conditions specified in the coal supply agreement, actual operating conditions at time of mining, type of preparation at time of mining, or federal and state regulations. Analysis intended for informational purposes only. Assumptions: 1) Equilibrium Moisture plus 3.0% for production moisture. 2) 3 inches of extraneous material added.



is shown in Figures 3.4-2 and 3.4-6. Each is described briefly below, with construction details and expanded maps.

Access/Haul Road. Primary site access for vehicular traffic would be from State Highway 59, approximately eight miles south of Reno Junction; east along the Reno County Road; south and east along Piney Canyon Road; and southeast along a 30-foot-wide, 5.3-mile-long access road to be completed into the site, shown (for initial mine operation) in Figure 3.4-2. All access road surfaces from the permit boundary to State Highway 59 would be upgraded, at Rochelle Coal Company's expense, to secondary highway standards. Access to the mine area would be controlled only by signs.

Railroad. The proposed electric railroad, for hauling coal to the gasification plant and returning ash to the mine for burial, is described in detail in Section 3.5. The 40-mile line, to run north from the plant, would terminate in a loop southwest of the facilities area, in T. 41 N., R. 70 W., sec. 16, as shown in Figure 3.4-6. Coal loading and ash unloading facilities would be located on this loop.

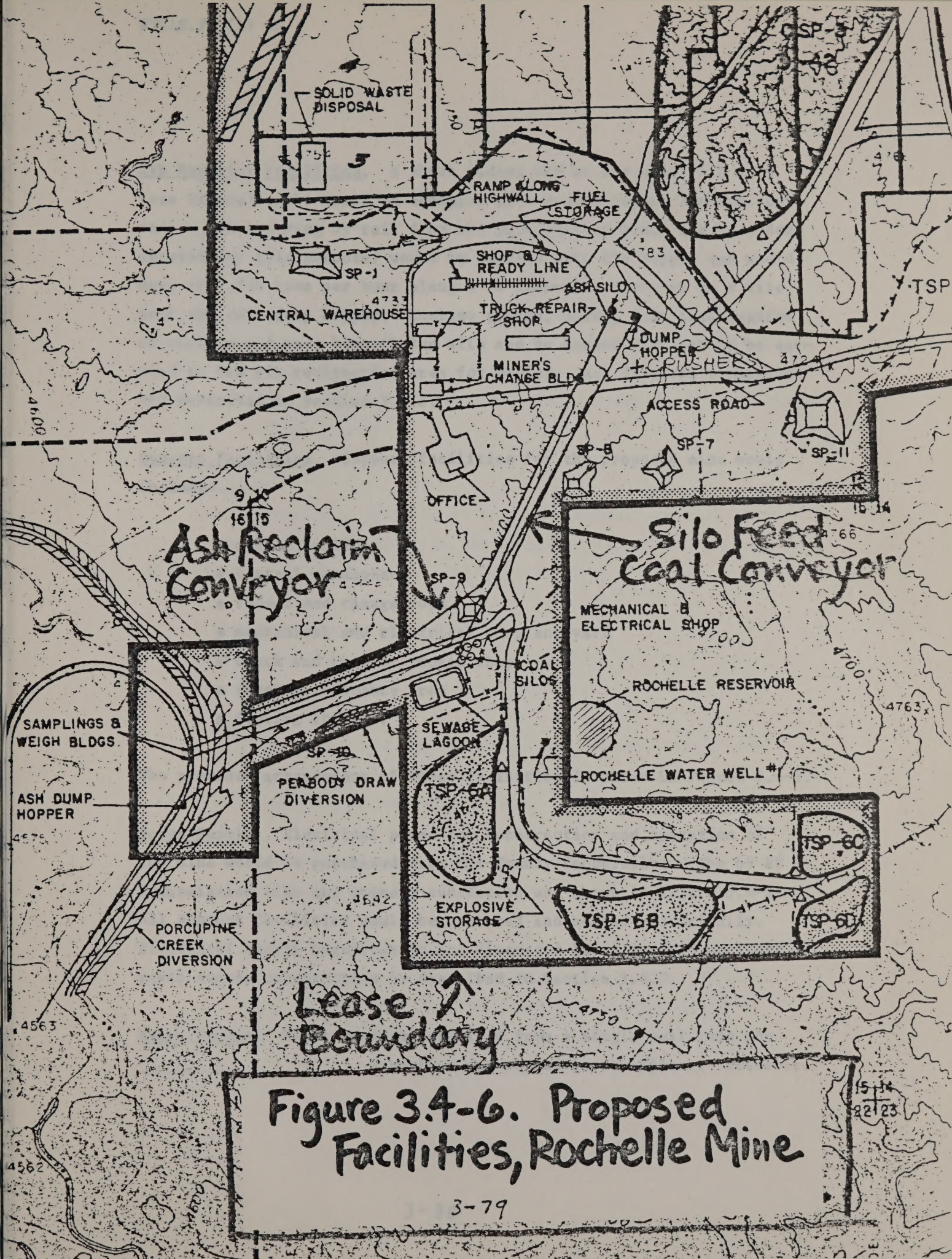
Coal Handling Facilities. Run-of-mine coal would be loaded at the pit by electric-powered shovel loaders, into 120-ton back-dump trucks, which would carry it to a 90-foot-deep dump hopper (see Figure 3.4-6). The hopper would contain the surge as the coal is fed through crushers and reduced to a 3-inch topsize. Crushed coal would move by a 72-inch-wide conveyor, 3,200 feet to one of 5 storage silos having a combined capacity of 75,000 tons. The silos would be linked to the loadout facility by two 72-inch-wide, 2,500-foot-long conveyors; when railroad cars are being loaded, the coal would be gravity fed onto the conveyor and into a weigh bin over the tracks. Before coal is discharged into individual cars, it would be automatically sampled and weighed.

is shown in Figures 1.4-1 and 1.4-2. Each is described briefly below with construction details and approximate costs.

Access Road. Primary access for vehicular traffic would be from State Highway 57, approximately 1/2 mile south of Lane Junction, east along the Reno Canyon Road, south and east along Pine Canyon Road, and south/east along a 30-foot-wide, 3/4-mile-long access road to be completed into the site, shown (for initial site operation) in Figure 1.4-1. All access road surfaces from the public boundary to State Highway 57 would be asphalt, at Rockwell Coal Company's expense, to secondary highway standards. Access to the mine area would be controlled only by signs.

Handling. The proposed electric railroad, for handling coal to the gasification plant and returning ash to the mine for burial, is described in detail in Section 3.2. The 40-mile line, to run north from the plant, would terminate in a loop northwest of the facilities near lat. 41 N., 105 W., sec. 16, as shown in Figure 1.4-2. Coal handling and new unloading facilities would be located on this loop.

Coal Handling Facilities. Run-of-mine coal would be loaded at the pit by electric-powered shovel loaders, into 110-ton hopper cars, which would carry it to a 70-foot-long dump hopper (see Figure 1.4-3). The hopper would contain the large size coal as it fell through screens and reduced to a 3-inch topsize. Graded coal would pass by a 75-foot-wide conveyor, 5,500 feet to one of 5 storage silos having a combined capacity of 75,000 tons. The silos would be linked to the loaders to carry by two 75-inch-wide, 5,500-foot-long conveyors, which would carry coal to the gasification plant. The coal would be gravity fed onto the conveyor and into a weigh bin over the reactor. Before coal is discharged into individual cars, it would be automatically sampled and weighed.





Ash Handling Facilities. A short siding off of the main rail loop (see Figure 3.4-6) would be equipped with a dump hopper beneath the rail. Ash arriving by rail from the gasification plant (in cars designated for this purpose) would be emptied into the hopper and would move at 1,330 tons per hour along a 36-inch-wide conveyor to a silo near the coal dump hopper. Haulage trucks, having just been emptied of coal, would pass beneath the silo and be loaded with ash to be carried to the pit reclamation area for burial. Ash disposal techniques are described in Section 3.4.3.

Support Facilities. Support facilities for the proposed mine would include:

- office building
- central warehouse
- shower and change room
- mechanical and electrical shop and yard
- truck and tractor repair shop
- truck maintenance area
- fueling station.

The proposed arrangement of these facilities is shown in Figure 3.4-6.

Power Supply. Electrical power for construction and operation of the mine would be purchased from Tri-County Cooperative. The 69 kV transmission line and primary substation are shown in Figure 3.4-6. All support facilities would be operated and heated electrically. Electrical energy requirements are discussed later in this section; power supply construction is described in Section 3.4.3.

Water Supply. Water would be obtained from a single well into the \_\_\_\_\_ Formation and stored in an adjacent reservoir.

Ash Handling Facilities. A short siding off of the main rail loop (see Figure 2-4-5) would be equipped with a crane hooper beneath the rail. Ash arriving by rail from the generation plant for the sub-located for this purpose) would be emptied into the hooper and would move at 1,350 tons per hour along a 10-foot-wide conveyor to a silo near the coal dump hooper. Loading trucks, having just been emptied of coal, would pass beneath the silo and be loaded with ash to be sent to the pit located near the hooper. Ash disposal techniques are described in Section 2-4-7.

Support Facilities. Support facilities for the proposed plant would include:

- office building
- control warehouse
- storage and change room
- mechanical and electrical shop and yard
- truck and crane repair shop
- rough maintenance area
- loading station.

The proposed arrangement of these facilities is shown in Figure 2-4-6.

Power Supply. Electrical power for construction and operation of the plant would be purchased from the Elkhart County Cooperative. The 69 kv transmission line and primary substation are shown in Figure 2-4-6. All support facilities would be operated and owned by the utility. Electrical energy requirements are discussed later in this section. Power supply construction is described in Section 2-4-7.

Water Supply. Water would be obtained from a nearby well into the treatment and stored in an adjacent reservoir.

Both would be located in section 15 as shown in Figure 3.4-6. The well would be drilled prior to the start of construction. Water requirements are discussed later in this section. A septic system and leaching field would be constructed to process sanitary wastes.

Signs and Markers. Signs would be posted for identification around the permit boundary, at all entrance points, and at all topsoil and overburden stockpiles. Signs explaining blasting procedures and schedules would be located at all mine entrance points. Typical signs are shown in Figure 3.4-7.

#### Mining Method

The Rochelle Mine would be a "truck-and-shovel" open-pit operation, typical of other mines in the Powder River Basin. The sequence of major steps would be as follows:

- Surface water control (ongoing).
- Topsoil removal and stockpiling.
- Overburden drilling, blasting, and removal. Except for the initial cut and other special conditions, this would go directly to mined-out areas.
- Coal drilling, blasting, and removal. Coal would be crushed to a 2-inch topsize at the mine.
- Overburden replacement and shaping, with the material most suitable as a root medium being placed on top. Ash and other solid waste from the gasification plant would be buried in this step.

Both would be located in section 15 as shown in Figure 3-4-5. The well would be drilled prior to the start of construction. Water requirements are discussed later in this section. A water system and leaching fluid would be constructed to provide constant water.

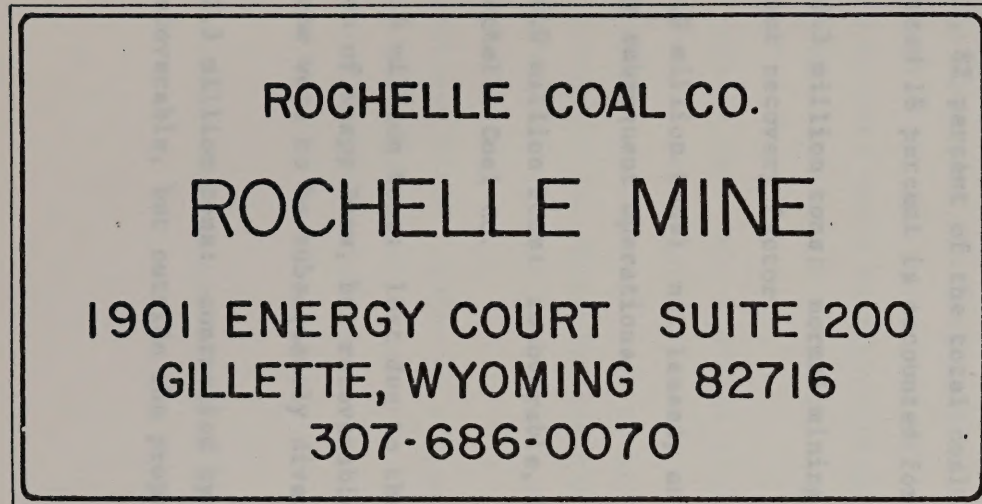
Signs and Markers. Signs would be placed for identification around the permit boundary, at all entrance points, and at all points and overburden stockpiles. Signs indicating blasting procedures and activities would be located at all other entrance points. Typical signs are shown in Figure 3-4-7.

Mining Method

The Rockwell Mine would be a "bench-and-shovel" open-pit operation. Typical of other mines in the Powder River Basin. The sequence of major steps would be as follows:

- 1. Surface water control (ditching).
- 2. Topsoil removal and stockpiling.
- 3. Overburden drilling, blasting, and removal. Steps for the initial cut and other special conditions. This would be directly to mine and stream.
- 4. Coal drilling, blasting, and removal. Coal would be loaded on a 1-inch topsoil at the mine.
- 5. Overburden replacement and shaping, with the material water suitable as a root medium being placed on top. All and other solid waste from the gasification plant would be buried in this step.

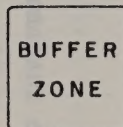
3-82



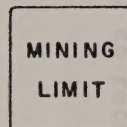
MAIN ENTRANCE SIGN



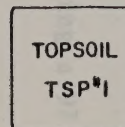
PERIMETER  
MARKERS



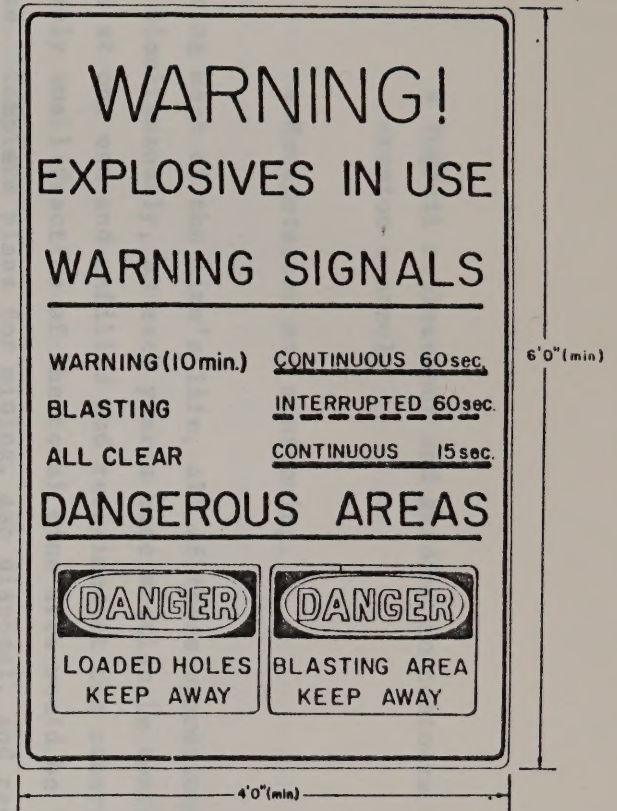
BUFFER  
ZONE  
MARKERS



LIMIT  
MARKERS  
(MISC.)



TOPSOIL  
MARKER



MAIN ENTRANCE BLASTING SIGN

Figure 3.4-7

TYPICAL  
SIGNS AND MARKERS,

Rochelle Mine



- Topsoil replacement and grading to contours suitable for erosion control.
- Revegetation and monitoring.

During most of the mine's life, all of these operations would be going on simultaneously, as each year's mine section is continuously stripped at one end and refilled and reclaimed at the other. Thus, a relatively small fraction of the total mine area would be "open" at any time. Complete plans for mining, ash disposal, and reclamation are discussed in Sections 3.4.3 and 3.4.4.

#### Coal Losses

Rochelle Coal Company proposes to recover and ship 411,500,000 tons of coal, 82 percent of the total coal within the permit area. The unrecovered 18 percent is accounted for as follows:

- 12.3 million tons: normal mining losses assuming a 97 percent recovery factor
- 3.2 million tons: not leased, and uneconomical to recover by subsequent operations
- 16.0 million tons: recoverable, but not controlled by Rochelle Coal Co.
- 6.4 million tons: lost due to the proposed permanent diversion of Knapp Draw, but recoverable in the future if Knapp Draw were to be subsequently diverted
- 52.3 million tons: controlled by Rochelle Coal Co., and recoverable, but outside the proposed extraction limits;



these limits protect Piney Canyon Road where it crosses the north end of the lease area.

To maximize coal recovery, reserve pits would be used for blending low-quality crop coal into the general production. An attempt would be made to recover small rider seams above the main seam (see Figure 3.4-5); the marketability of these stringers is questionable, however, and they have not been considered as a resource. Blasting procedures would minimize the mixing of overburden and coal, and the resulting loss of coal.

#### Energy and Water Requirements

In a typical year of full production (11 million tons of coal produced; 22.3 million yd<sup>3</sup> of overburden moved), electrical requirements for mine operation are projected to be 33.5 MW, apportioned as shown in Table 3.4-3. All space heating would be electric; power shovels and conveyors would be electrically operated. The electrical supply system is discussed in section 3.8.

Typical diesel fuel (no. 2 diesel oil) use is projected to be 3.1 million gallons per year, apportioned as shown in Table 3.4-4. Approximately 180,000 gallons per year of gasoline would be used during production, primarily for small service vehicles. Assumptions on which the above estimates are based are summarized in Appendix 1.

Mine operation would require an estimated 229,200 gallons per day (gpd) of water to be obtained from a single deep well, and to be apportioned as shown in Table 3.4-5.

#### Waste Stream

Construction waste components and disposal plans would be as follows:



Table 3.4-3

## ELECTRICAL REQUIREMENTS, ROCHELLE MINE OPERATION

---

Overburden Removal	22.3 MW
Coal Processing	5.6 MW
Shop & Office Support	5.6 MW

---

Headframe & other Support	240,000 gal
Reclamation	160,000 gal

---



Table 3.4-4

## DIESEL FUEL REQUIREMENTS, ROCHELLE MINE OPERATION

---

Explosives (ANFO) Component	61,000 gal
Overburden Removal & Haulage	1,700.000 gal
Coal Drilling & Haulage	910,000 gal
Road Maintenance & Other Support	240,000 gal
Reclamation	160,000 gal

---



Table 3.4-5

## WATER REQUIREMENTS, ROCHELLE MINE OPERATION

---

Dust suppression	200,000 gpd
Other non-potable uses (equipment cleaning, showers, etc.)	16,200 gpd
Potable uses	13,000 gpd

---



- Human waste: contractor-maintained portable toilets
- Solid construction waste: permitted landfill
- Storm runoff: NPDES-approved settling ponds and discharge points (see section 3.4.2)
- Settling pond sediment: post-construction burial.

Discharge would be intermittent, and there would be no heated effluents.

The operational waste stream and disposal plans would be as follows:

- Human waste: permitted sewage lagoon
- Solid waste: permitted landfill
- Spent oil and solvents: recycled
- Storm runoff: NPDES-approved settling ponds and discharge points (see section 3.4.2)
- Settling pond sediment: burial with mine spoil at approximately one-year intervals.

Discharge would be intermittent, with no heated effluents.

#### Air Pollution Control

(Awaiting further information from Rochelle Coal Co.)

#### Construction and Production Schedule

Facilities construction at the Rochelle Mine would begin in \_\_\_\_\_ and last for two years. Coal production would begin in \_\_\_\_\_, building up to full production in \_\_\_\_\_. Reclamation and ash burial would begin in \_\_\_\_\_, and continue for the life of the



## Figure 3.4-8

## Construction Schedule, Rochelle Mine

mine. Mine lifetime (including construction time) would be 32 years for purposes of this project, but reserves allow for a 42-year life at 11 million tons of annual production. Figure 3.4-8 depicts the proposed detailed schedule for facilities construction and equipment erection. Table 3.4-6 is a summary, by year, of land disturbance and coal production, and Figure 3.4-9 shows the sequence of areas mined of coal. An average of 128 acres would be disturbed each year.

Workforce

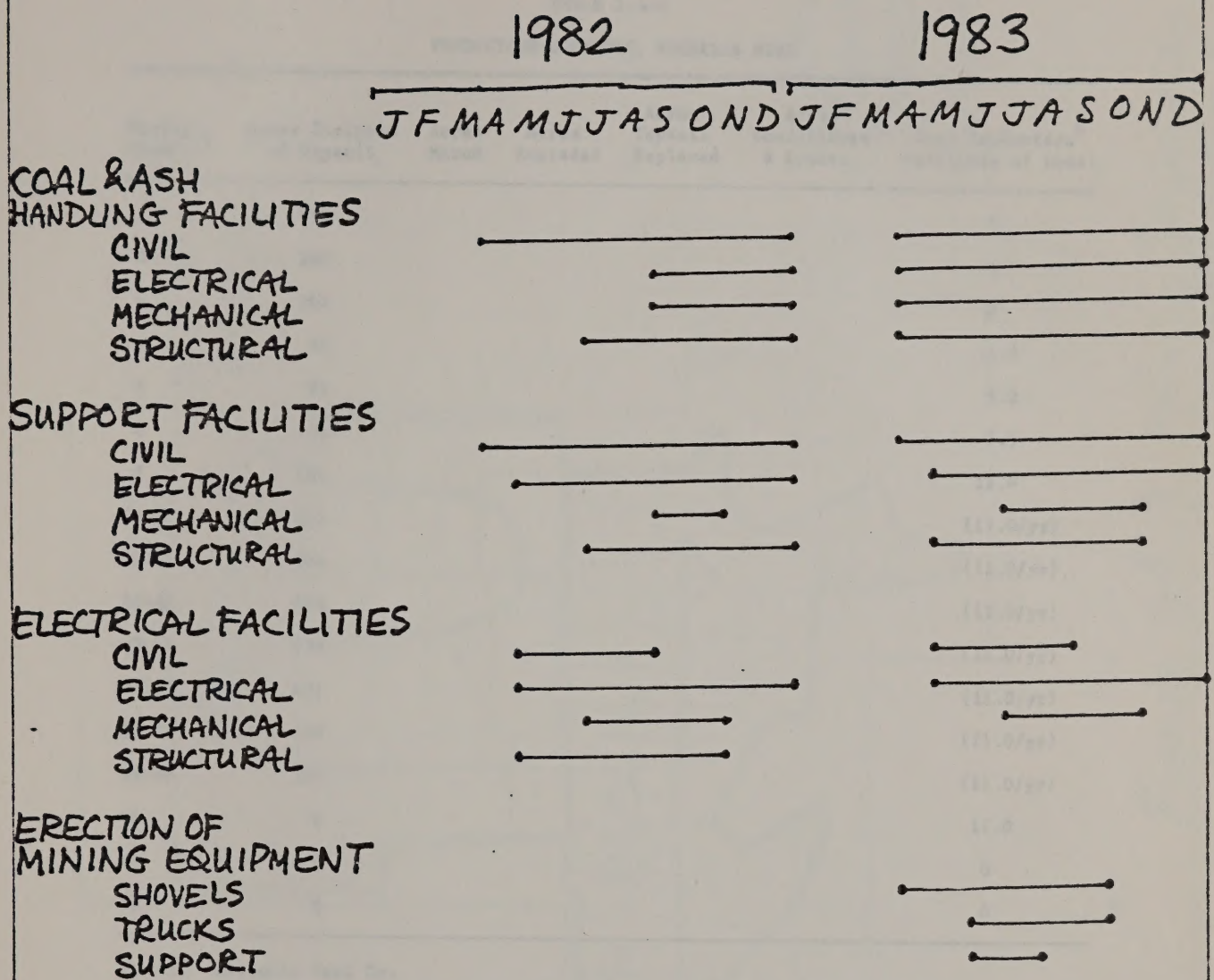
The Rochelle Coal Company has maintained a staff of approximately 8 in Gillette, Wyoming, since 1980, for purposes of reserve exploration, drilling, surveying, and other pre-development activities. In Table 3.2-1 is a summary of construction and operation personnel requirements.

also. Mine lifeline (including construction time) would be 32 years for purposes of this project, but necessary life for a 40-year life at 11 million tons of annual production. Figure 3.4-5 depicts the proposed detailed schedule for facilities construction and equipment erection. Table 3.4-6 is a summary, by year, of land disturbance and coal production, and Figure 3.4-7 shows the schedule of annual mine of coal. An average of 128 acres would be disturbed each year.

Workforce

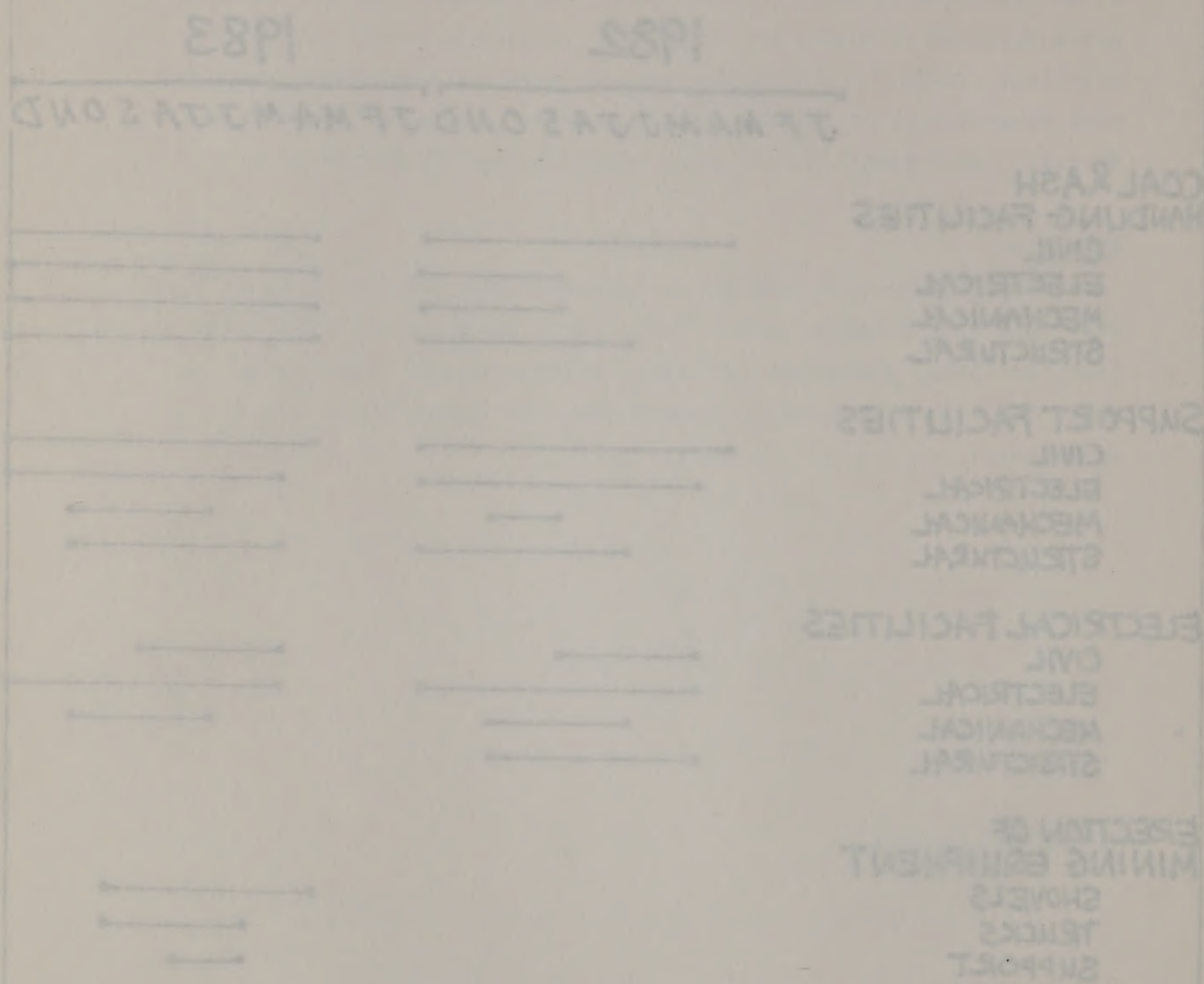
The Rockwell Coal Company has maintained a staff of approximately 8 in Elkhart, Wyoming, since 1960, for purposes of mine exploration, drilling, surveying, and other pre-development activities. In Table 3.4-8 is a summary of construction and operation personnel requirements.

Figure 3.4-8  
Construction Schedule, Rochelle Mine



Source: Rochelle Coal Co.

# Construction Schedule, Rochelle Mine Figure 3.4-8



Source: Rochelle Coal Co.

TABLE 3.4-6  
PRODUCTION SCHEDULE, ROCHELLE MINE

Mining Year(s) <sup>a</sup>	Acres Stripped of Topsoil	Acres Mined	Acres Regraded	Acres Topsoil Replaced	Acres Conditioned & Seeded	Coal Production <sup>b</sup> (millions of tons)
1	356					0
2	242					0
3	260					0
4	85					2.5
5	85					5.0
6	110					7.5
7	106					11.0
8-12	375					(11.0/yr)
13-17	954					(11.0/yr)
18-22	668					(11.0/yr)
23-27	776					(11.0/yr)
28-32	491					(11.0/yr)
33-37	428					(11.0/yr)
38-39	169					(11.0/yr)
40	0					11.0
41	0					0
42	0					0

Source: Rochelle Coal Co.

<sup>a</sup>Years are counted from completion of construction.

<sup>b</sup>This includes an estimated 30 percent of fines unsuitable for Lurgi gasification. About 80 percent of fines would be used for power generation at the gasification plant; the rest would be sold.



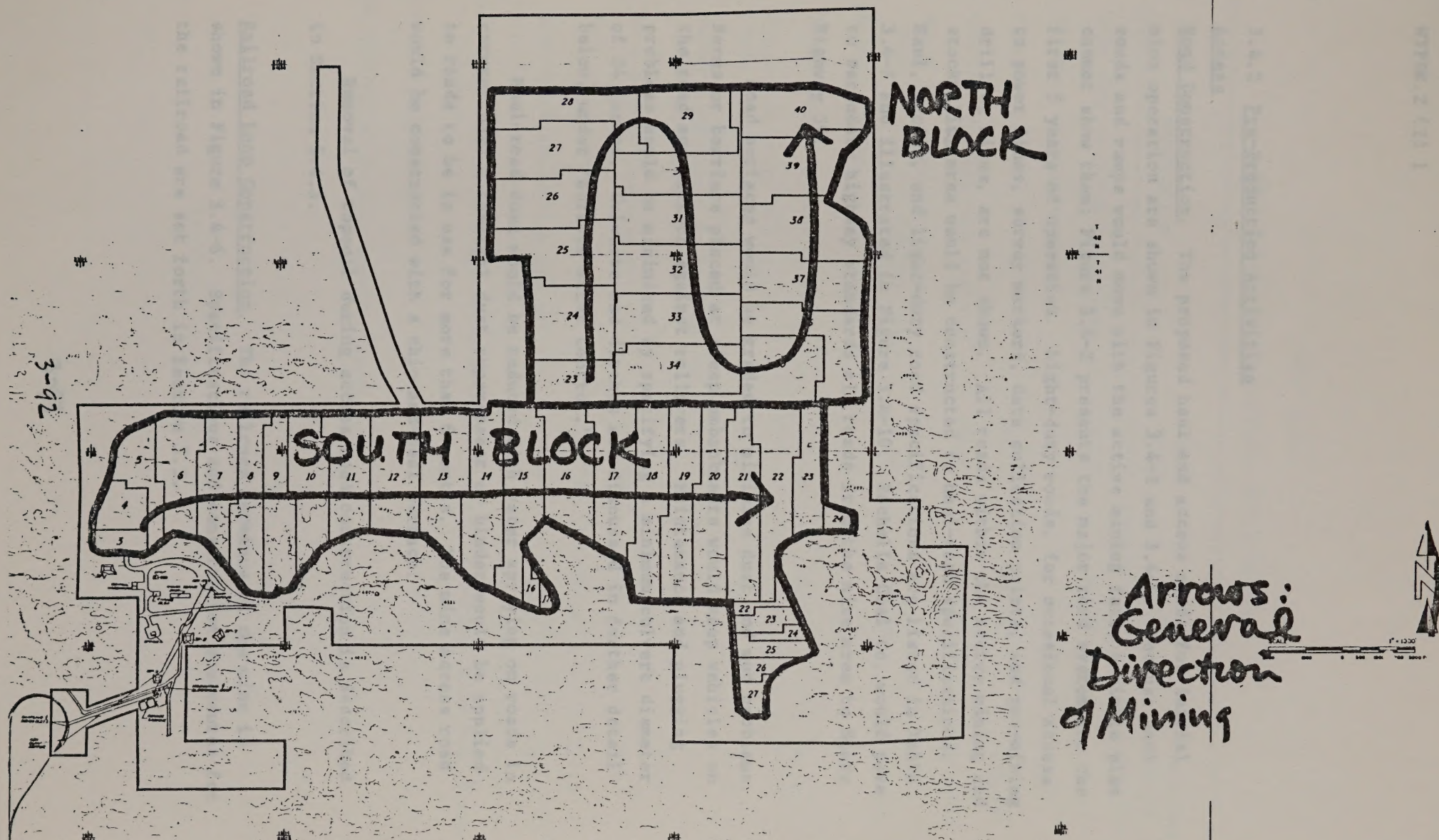


Figure 34-9. Mining Sequence,  
Rockwell Mine



### 3.4.2 Pre-Production Activities

#### Access

Road Construction. The proposed haul and access roads for initial mine operation are shown in Figures 3.4-2 and 3.4-6. Because haul roads and ramps would move with the active mining face, a single plan cannot show them; Figure 3.4-2 presents the major road system for the first 5 years of operation. Light-duty roads, for occasional access to power lines, survey markers, data collection points, and pre-mining drilling sites, are not shown. All roads within the active mining and stockpiling area would be constructed to haul-road specifications. Haul, access, and light-duty road specifications are listed in Table 3.4-7 and illustrated in Figure 3.4-10. Rochelle Coal Co. would pave to secondary highway standards all roads from the mine area to State Highway 59.

Road surfaces would be graded to minimize dust and mud problems. Berms or barriers placed at steep embankments would keep vehicles on the road and protect against rollovers. Maintenance and plugging problems would be minimized by specifying a minimum culvert diameter of 24 inches. Culverts and ditches are discussed in further detail below, under "Surface Water Control."

Haul-road dust would be reduced with water spraying on roads in current use; a chemical dust suppressant or binder would be applied to roads to be in use for more than 6 months. The mine access road would be constructed with a chip-and-seal surface.

Removal of topsoil during access road construction is described in Section 3.4.3.

Railroad Loop Construction. The railroad terminus at the mine is shown in Figure 3.4-6. Specifications and construction procedures for the railroad are set forth in Section 3.5.

# 1.4.2 Pre-Production Activities

## Access

Road Construction. The proposed haul and access roads for initial mine operation are shown in Figure 1.4-2 and 1.4-3. Between haul roads and ramps would move with the active mining face, a stable plan cannot show them; Figure 1.4-2 presents the major road system for the first 5 years of operation. Light-duty roads, for occasional access to power lines, survey markers, data collection points, and providing drilling sites, are not shown. All roads within the active mining and stockpiling areas would be constructed to haul-road specifications. Haul, access, and light-duty road specifications are listed in Table 1.4-7 and illustrated in Figure 1.4-10. Rockville Coal Co. would have to secondary highway standards all roads from the mine area to State Highway 20.

Road surfaces would be graded to eliminate dust and mud problems. Gravel or crushed stone placed in wheel depressions would keep vehicles on the road and protect against rollovers. Maintenance and grading problems would be anticipated by specifying a minimum wheel diameter of 36 inches. Graders and rollers are discussed in further detail below, under "Surface Water Control."

Haul-road dust would be reduced with water spraying on roads in current use; a chemical dust suppressant or binder would be applied to roads to be in use for more than 6 months. The mine access road would be constructed with a chip-and-seal surface.

Removal of topsoil during access road construction is described in Section 1.4.3.

Relined Loop Construction. The relined remains of the mine is shown in Figure 1.4-8. Specifications and construction procedures for the railroad are set forth in Section 1.5.

TABLE 3.4-7

## ROAD DESIGN SPECIFICATIONS, ROCHELLE MINE

Key <sup>a</sup>	Description	Haul Roads	Access Road	Light Use Roads
a.	Lane edge to ditch centerline	8-12'	8-12'	2'
b.	Width of driving surface	80'	30-60	10'
c.	Cross slope	24h:1v	24h:1v	24h:1v
d.	Combined surface plus subbase <sup>b</sup>	12-48"	12-48"	variable
e.	Ditch out slope (angle of repose in rock - 0.25h:1v) (MAX)	1.5h:1v	1.5h:1v	1.5h:1v
f.	Depth at ditch center line <sup>b</sup>	--	--	--
g.	Ditch slope adjacent to roadway	2h:1v	2h:1v	2h:1v
h.	Extra road width for safety berm (if required)	20'	12'	None
i.	Safety berm height is rolling radius of largest tire	5'	3'	None
j.	Berm support (subbase material)	scoria	N/A	N/A
k.	Fill slope (MAX)	2h:1v	2h:1v	2h:1v
l.	Fill bench when slope exceeds 1:1	N/A	N/A	N/A

Source: U.S. Bureau of Mines Circular 8758, "Design of Surface Mine Haul Roads-A Manual."

<sup>a</sup>Refer to Figure 3.4-9.

<sup>b</sup>To be determined by site-specific conditions.

TABLE 3.4-7  
ROAD DESIGN SPECIFICATIONS, ROUNDBAY WYOMING

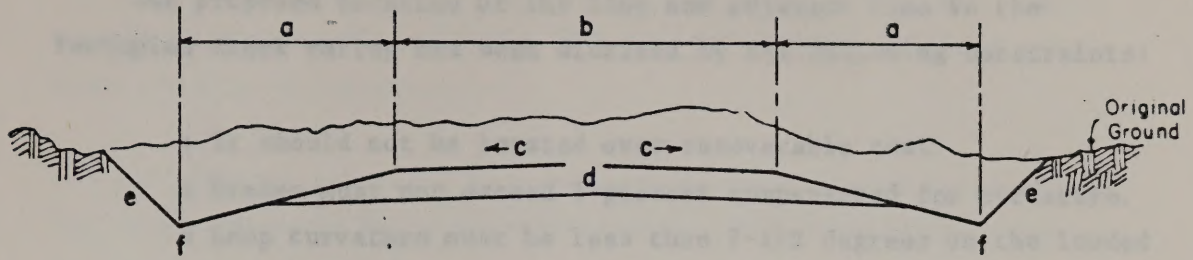
Key <sup>a</sup>	Description	Right of Way	Access Road	Light New
a.	Lane edge to ditch construction	8-12'	8-12'	2'
b.	Width of driving surface	50'	50-60'	10'
c.	Cross slope	2.0% to 4.0%	2.0% to 4.0%	2.0% to 4.0%
d.	Combined surface plus shoulder <sup>b</sup>	12-15'	12-15'	variable
e.	Ditch out slope (angle of repose in rock - 0.25:1) (MAX)	1:1.5 to 1:2.0	1:1.5 to 1:2.0	1:1.5 to 1:2.0
f.	Depth of ditch center line <sup>b</sup>	—	—	—
g.	Ditch slope adjacent to roadway	2:1 to 3:1	2:1 to 3:1	2:1 to 3:1
h.	Extra road width for safety berm (if required)	20'	20'	None
i.	Safety berm height is rolling radius of largest tire	2'	2'	None
j.	Berm support (subbase material)	as needed	N/A	N/A
k.	Fill slope (MAX)	2:1 to 3:1	2:1 to 3:1	2:1 to 3:1
l.	Fill bench when slope exceeds 1:1	N/A	N/A	N/A

Source: U.S. Bureau of Mines Circular 8758, "Design of Surface Mine Roadways-A Manual."

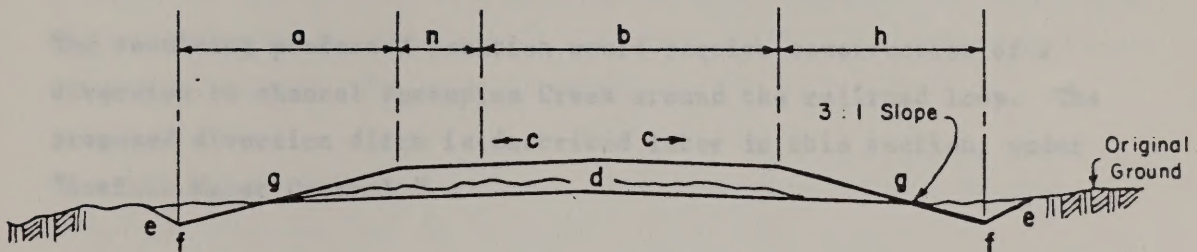
<sup>a</sup>Refer to Figure 3.4-2.

<sup>b</sup>To be determined by site-specific conditions.

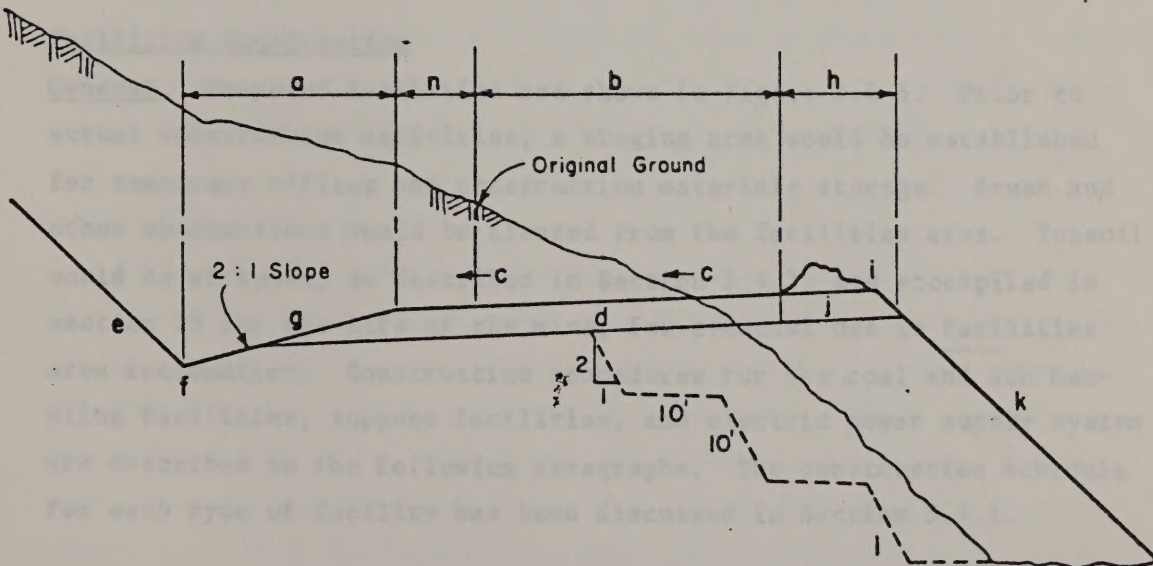
Figure 3.4-10. Generalized Road  
Sections, Rochelle Mine  
(Refer to Table 3.4-7)



TYPICAL CUT SECTION



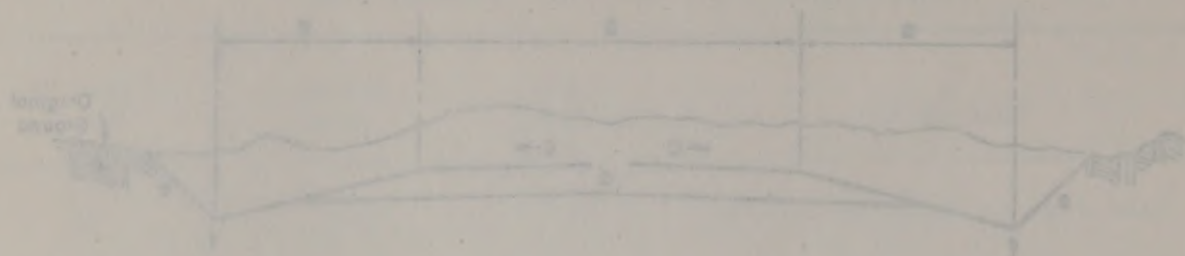
TYPICAL FILL SECTION



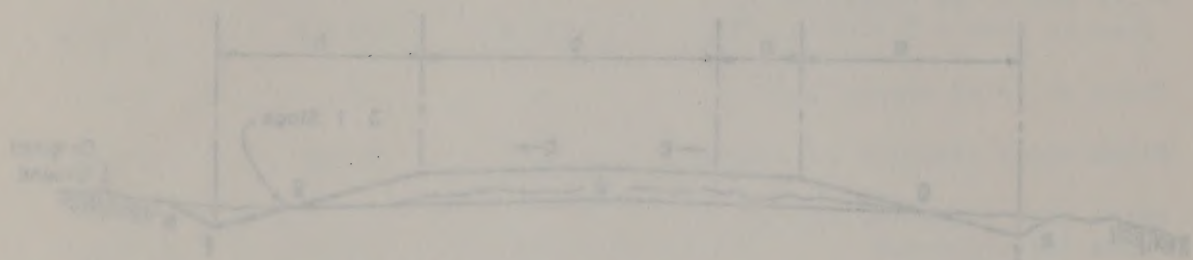
TYPICAL CUT - FILL SECTION

From "USBM IC 8758 "DESIGN OF SURFACE MINE HAUL ROADS-A MANUAL"

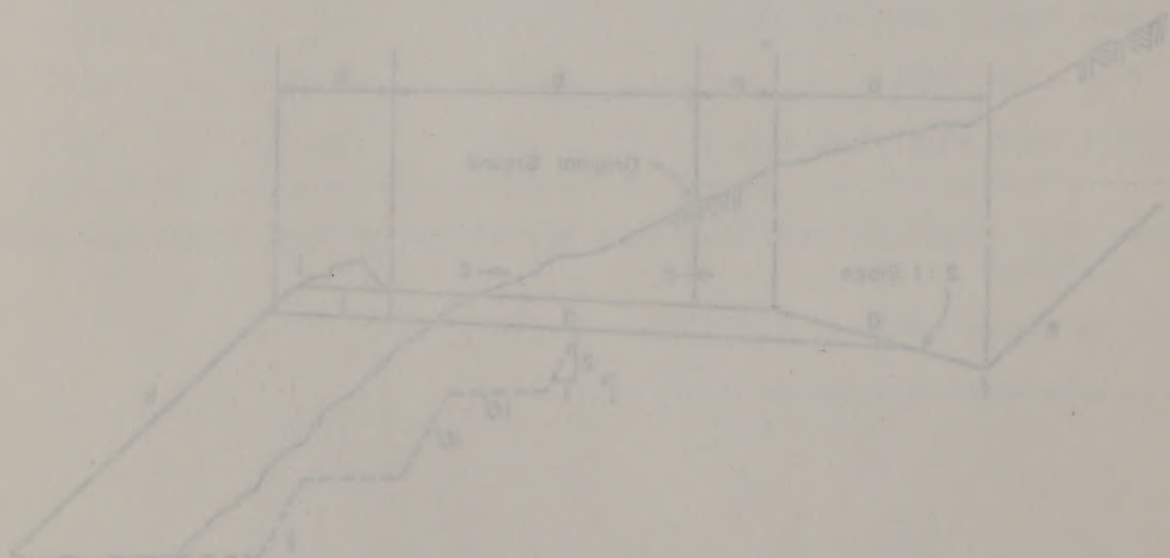
Figure 3A-10. Generalized Road  
Sections, Rockville Mine  
(Refer to Table 3A-7)



TYPICAL CUT SECTION



TYPICAL FILL SECTION



TYPICAL CUT - FILL SECTION

From "DESIGN OF SURFACE MINING ROAD-A MANUAL"

The proposed location of the loop and adjacent line in the Porcupine Creek valley has been dictated by the following constraints:

- It should not be located over recoverable coal.
- Grades must not exceed 1 percent compensated for curvature.
- Loop curvature must be less than 7-1/2 degrees on the loaded side, and 8 degrees on the empty side, without excessive cut and fill.
- It must avoid eagle roosting or nesting sites in the Porcupine Creek valley.

The resulting preferred location would require construction of a diversion to channel Porcupine Creek around the railroad loop. The proposed diversion ditch is described later in this section, under "Surface Water Control."

#### Water Supply Development

(Awaiting further information from Rochelle Coal Co.)

#### Facilities Construction

General. Proposed facilities are shown in Figure 3.4-6. Prior to actual construction activities, a staging area would be established for temporary offices and construction materials storage. Brush and other obstructions would be cleared from the facilities area. Topsoil would be stripped, as described in Section 3.4.3, and stockpiled in section 15 for the life of the mine, for eventual use in facilities area reclamation. Construction procedures for the coal and ash handling facilities, support facilities, and electric power supply system are described in the following paragraphs. The construction schedule for each type of facility has been discussed in Section 3.4.1.

The proposed location of the loop and adjacent line in the  
Tongue River valley has been discussed in the following paragraphs:

It should not be located over watercourses.  
Grades must not exceed 1 percent (maximum for waterways).  
A loop structure must be less than 7-1/2 degrees on the loaded  
side, and 5 degrees on the empty side, without excessive cut  
and fill.  
It must avoid any crossing or setting along in the  
Tongue River valley.

The resulting proposed location would require construction of a  
diversion to channel Tongue River around the railroad loop. The  
proposed diversion ditch is described later in this section, under  
"Surface Water Control."

Water Supply Development

(Awaiting further information from Pacific Coal Co.)

Facilities Construction

General. Proposed facilities are shown in Figures 3-4-5. Water to  
actual construction activities, a staging area would be established  
for temporary offices and construction materials storage. Brush and  
other obstructions would be cleared from the facilities area. Topsoil  
would be stripped, as described in Section 3-4-6, and stockpiled in  
section 15 for the life of the mine. For electrical use in facilities  
area construction. Construction equipment for the coal and ash han-  
dling facilities, support facilities, and electric power supply system  
are described in the following paragraphs. The construction schedule  
for each type of facility has been discussed in Section 3-5-1.

Construction materials would move largely by truck from Casper along U.S. Highway 87 and State Highway 387, and from Gillette along State Highway 59 (Figure 1.1-1).

All foundations would be constructed of reinforced concrete. Concrete work would be in accordance with Standard Specifications of the American Concrete Institute (ACI-38-71). All steel structures would be designed, fabricated, and erected in accordance with Standard Specifications for Structural Steel for buildings as adopted by the American Institute of Steel Construction. Structures would be designed on the basis of the American National Standard for structures in this geographical location (A.S.A. A58. 1-1972) for a 50-year mean recurrence interval for snow and wind.

Coal and Ash Handling Facilities. (Awaiting construction information from Rochelle Coal Co.)

Support Facilities. These include offices, truck maintenance and repair shops, mechanical and electrical building, warehouse, fuel station, and change rooms; locations are shown on Figure 3.4-6. Standard building construction methods would be used. Some work on these facilities could be extended past the start of production.

#### Surface Water Control

During and after mining operations, surface water flow at the site would be controlled in order to minimize impacts to water quality and quantity. This control would be accomplished by berms, channels, and culverts constructed to direct flow away from mining activities, where this is feasible, and ditches and sedimentation ponds to collect, clarify, and discharge flows that cannot be diverted. Design details have been developed for control facilities to be used during mining years 1 through 5; these are shown on Figure 3.4-11, and are

Figure 3.4-11. Surface Water Control, Rochelle Mine

Construction materials would be transported by truck from Casper along U.S. Highway 87 and State Highway 387, and from Gillette along State Highway 39 (Figure 1.1-1).

All foundations would be constructed of reinforced concrete. Concrete work would be in accordance with Standard Specifications of the American Concrete Institute (ACI-308-71). All steel structures would be designed, fabricated, and erected in accordance with Standard Specifications for Structural Steel for Buildings as adopted by the American Institute of Steel Construction. Structures would be designed on the basis of the American National Standards for structures in this geographical location (A.S.A. 1-1-71) for a 50-year mean recurrence interval for snow and wind.

#### Coal and Ash Handling Facilities (including construction facilities from Rockwell Coal Co.)

Support Facilities - These include offices, truck maintenance and repair shops, mechanical and electrical building, warehouses, fuel station, and change rooms; locations are shown on Figure 1.1-2. Standard building construction methods would be used. Some work on these facilities could be extended past the start of production.

#### Surface Water Control

During and after mining operations, surface water flow at the site would be controlled in order to minimize damage to water quality and quantity. This control would be necessary to prevent erosion, sedimentation, and collapse connected to direct flow away from mining activities, where this is feasible, and ditches and sedimentation ponds to collect, clarify, and discharge flows that cannot be directed. Design details have been developed for control facilities to be used during mining years 1 through 5; these are shown on Figure 1.1-3, and are

(TO BE REVISED)

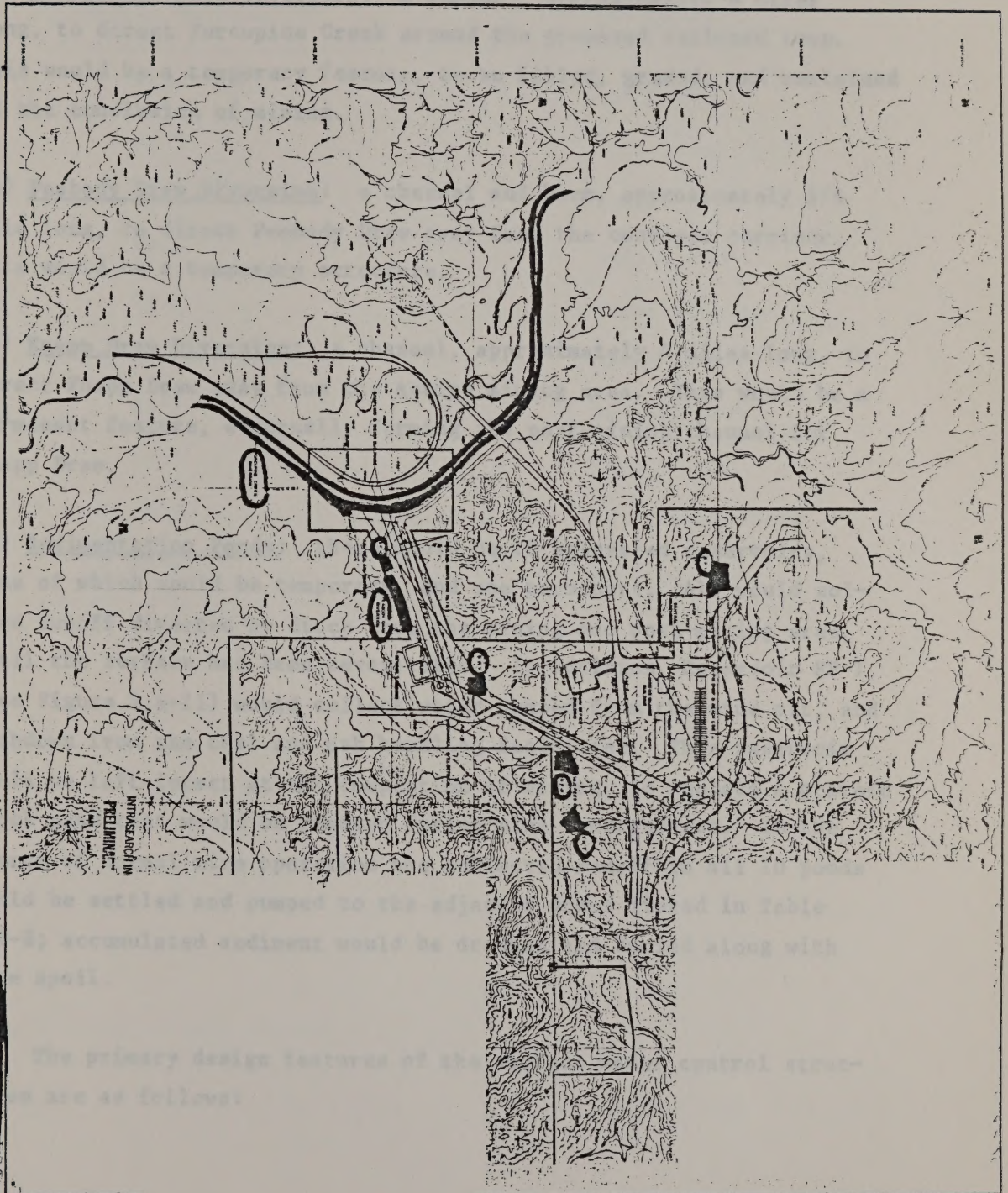


Figure 3.4-11. Surface Water Control, Rochelle Mine

(TO BE REVERSED)

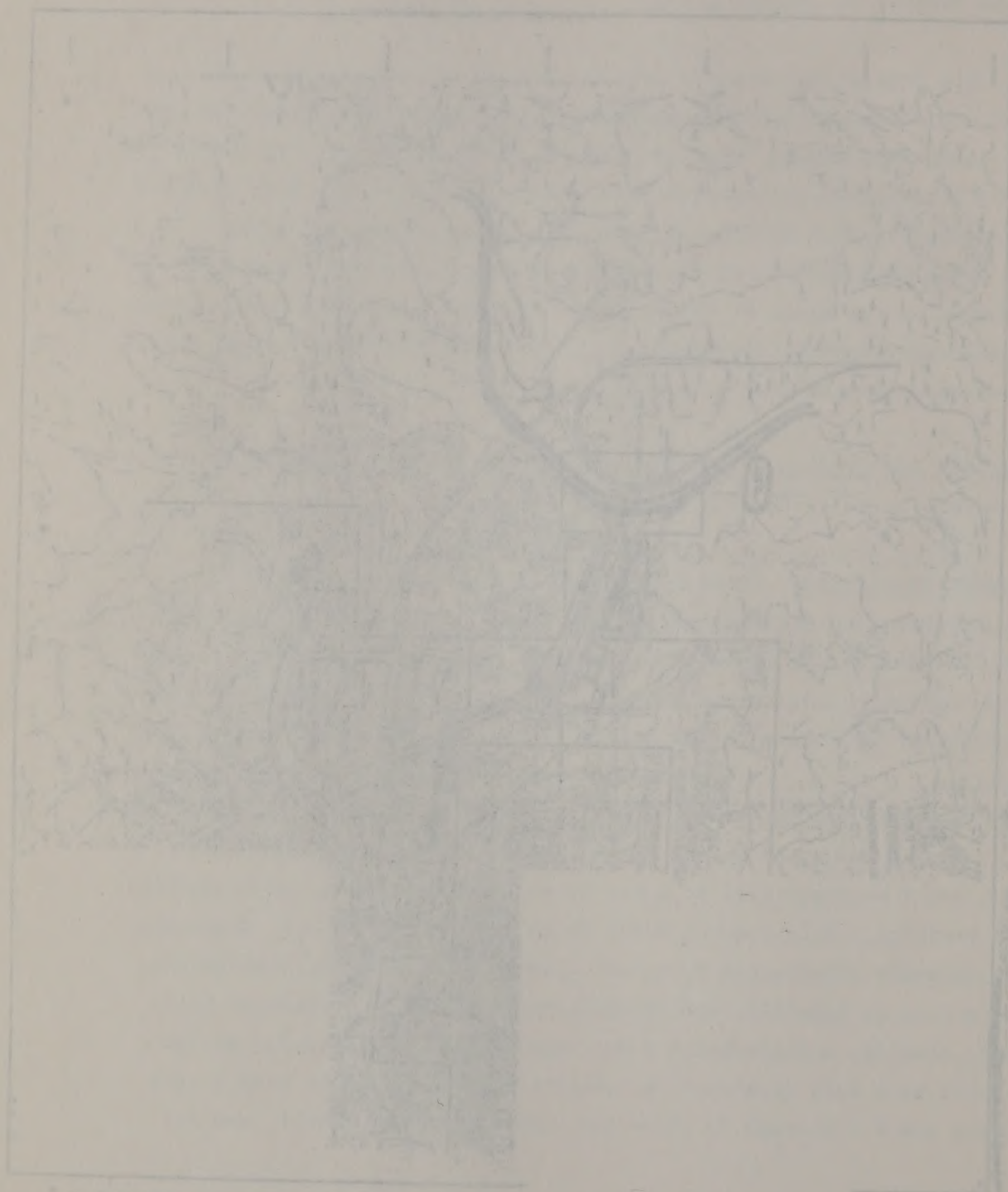


Figure 34-11. Son Force Water Control, Rochelle Mine.

briefly described below:

- (a) Porcupine Creek Diversion: a channel, approximately 8 miles long, to direct Porcupine Creek around the proposed railroad loop. This would be a temporary feature, to be filled, graded, and reclaimed at the conclusion of mining.
- (b) Peabody Draw Diversion: a channel and berm, approximately 3/4 mile long, to direct Peabody Draw away from the conveyor corridor. This would be a temporary structure.
- (c) Knapp Draw Diversion: a channel, approximately 4 miles long, to direct Knapp Draw away from the active mining area. This would be a permanent feature, eventually forming the post-mining channel for Knapp Draw.
- (d) Sedimentation Ponds: there would be 10 excavated reservoirs, nine of which would be temporary, and one permanent. All would collect runoff diverted by ditch from the mining and post-mining area, until the surface has been revegetated. In addition, Reservoir SP-1 (see Figure 3.4-11) would collect water pumped from the mine pit, and washdown from the coal and ash handling facilities. This reservoir would be left intact at the completion of mining, to replace a private stock pond that would be removed during mine construction. In the course of normal mine operation the collected runoff in all 10 ponds would be settled and pumped to the adjacent draws listed in Table 3.4-8; accumulated sediment would be dredged and buried along with mine spoil.

The primary design features of the surface water control structures are as follows:

briefly described below:

(a) Portuguese Creek Diversion: a channel, approximately 5 miles long, to direct Portuguese Creek around the proposed railroad loop. This would be a temporary feature, to be filled, graded, and reclaimed at the completion of mining.

(b) Knappey Draw Diversion: a channel and dam, approximately 1 1/2 miles long, to direct Knappey Draw away from the conveyor corridor. This would be a temporary structure.

(c) Knappey Draw Diversion: a channel, approximately 5 miles long, to direct Knappey Draw away from the conveyor mining area. This would be a permanent feature, eventually forming the post-mining channel for Knappey Draw.

(d) Reclamation Ponds: there would be 14 reclamation ponds, nine of which would be temporary, and one permanent. All would collect runoff diverted by ditches from the mining and processing areas, until the surface has been revegetated. In addition, Knappey Draw (see Figure 3.4-11) would collect water pumped from the mine pit and washdown from the coal and mill handling facilities. This runoff would be left intact at the completion of mining, to replace a private stock pond that would be removed during mine construction. In the course of normal mine operation the accumulated runoff in all 14 ponds would be settled and pumped to the adjacent ditches listed in Table 3.4-8; accumulated sediment would be dredged and hauled along with mine spoil.

The primary design features of the sediment water control system are as follows:

TABLE 3.4-8

SEDIMENTATION PONDS AND  
DISCHARGE LOCATIONS, ROCHELLE MINE

Reservoir Designation	Discharged to:
SP-1	Red Draw
SP-2	Deer Mouse Draw
SP-3	Badger Draw
SP-4	Badger Draw
SP-5	Jackalope Draw
SP-6	Skunk Draw
SP-7	Red Fox Draw
SP-8	Coyote Draw
SP-9	Rattlesnake Draw
SP-10	Peabody Draw

TABLE 1-4-5  
SEDIMENTATION POINTS AND  
DISTANCE LOCATIONS, SODASVILLE RIVER

Sedimentation Points and Distance Locations, Sodasville River	
Distance from Sedimentation Point	Sedimentation Point
25-1	Red House
25-2	Red House Dam
25-3	Red House Dam
25-4	Red House Dam
25-5	Red House Dam
25-6	Red House Dam
25-7	Red House Dam
25-8	Red House Dam
25-9	Red House Dam
25-10	Red House Dam

- Sediment Ponds:

- Minimum storage volume greater than 3 years sediment accumulation plus runoff volume from a 10-year, 24-hour storm.
- No discharge from the pond during a 10-year, 24-hour storm.
- Emergency spillways capable of passing peak flow from a 25-year, 24-hour storm.

- Temporary Drainage Ditches:

- Backfill area ditches to carry peak flow from a 10-year, 24-hour storm; facilities area ditches to carry peak flow from a 25-year thunderstorm.
- Flow velocity less than 3 feet per second on erodible soils.

- Permanent Diversion Ditches:

- To pass runoff from a 100-year thunderstorm.
- Excavated in bedrock to prevent excessive erosion.
- To mimic essential pre-mining morphology.

- Culverts:

- Pass runoff from a 25-year, 1-hour thunderstorm without impounding water at the upstream end, and from a 100-year, 24-hour precipitation event, if warranted for certain facilities.
- To have erosion protection at discharge point if velocity exceeds 6 feet per second in a 25-year, 1-hour event.

### Erection of Mining Equipment

Heavy mining equipment, particularly electric shovels and large-capacity haulers for overburden and coal, would be brought in sections

Sediment Loads:

- \* Minimum storage volume required from 5 years sediment accumulation plus runoff volume from a 10-year, 24-hour storm.
- \* No discharge from the pond during a 10-year, 24-hour storm.
- \* Emergency spillways capable of passing peak flow from a 15-year, 24-hour storm.

Emergency Spillway Elevation:

- \* Backfill area ditches to carry peak flow from a 10-year, 24-hour storm; facilities area ditches to carry peak flow from a 15-year flood.
- \* Flow velocity less than 5 feet per second on stable soils.

Emergency Diversion Elevation:

- \* To pass runoff from a 100-year flood.
- \* Located in backwash to prevent excessive erosion.
- \* To provide essential post-storm vegetation.

Outfall:

- \* Pass runoff from a 15-year, 1-hour flood.
- \* Impounding water at the upstream end, and from a 100-year, 24-hour precipitation event, is retained for certain facilities.
- \* To have erosion protection at discharge point if velocity exceeds 5 feet per second in a 15-year, 1-hour event.

Excavation of Mining Equipment

Heavy mining equipment, particularly electric shovels and large capacity haulers for overburden and coal, would be brought in sections

to the mine site. Equipment would be assembled on a site near the mine buildings, and moved to the initial mining area several months in advance of the beginning of coal production, to allow time for equipment checks and initial topsoil and overburden removal.

### 3.4.3 Mining and Associated Operations

#### General Procedure

Mining Method. The Rochelle Mine, as noted in Section 3.4.1, would be a truck-and-shovel operation. Mining procedure would be as follows:

- Topsoil which has been judged salvageable would be removed by scrapers and, at the outset, stockpiled in section 15 for eventual reclamation use. When mining has reached a steady state, the topsoil would be moved directly to backfilled areas.
- Overburden would be drilled, blasted, and loaded by 20-yd<sup>3</sup> electric-powered shovels into 150-ton capacity diesel-powered haulers. Where possible it would be deposited in an adjacent mined-out area; otherwise it would be stockpiled in one of several locations. Overburden removal would take place simultaneously on three or four steps or "benches" up to 50 feet high, each at least 225-feet wide.
- Coal would be similarly drilled, blasted, and loaded into 120-ton capacity haulers, and carried to dump hoppers feeding the crushers. Coal would be mined on two equal benches spanning the seam thickness, with at least 200 feet between benches.

to the mine site. Equipment would be assembled on a site near the mine buildings, and moved to the initial mining area several months in advance of the beginning of coal production, to allow time for deep-vent checks and initial regional and overburden removal.

3.4.3 Mining and Associated Operations

General Procedure

Mining Method. The Doublet Mine, as noted in Section 3.4.1, would be a truck-and-shovel operation. Mining procedures would be as follows:

A topsoil which has been judged satisfactory would be removed by excavators and, at the proper, stockpiled in sections 15 feet or less in width. When mining has ceased, a steady state, the topsoil would be moved directly to backfilled areas.

A conveyor would be drilled, blasted, and loaded by 10-ton electric-powered shovels into 100-ton capacity dump-powered haulers. Where possible it would be deposited in an adjacent mine-out area; otherwise it would be stockpiled in one of several locations. Conveyors would place simultaneously on three or four acres of "benches" up to 50 feet high, each at least 100 feet wide.

Coal would be similarly drilled, blasted, and loaded into 100-ton capacity haulers, and carried to dump beyond the conveyor. Coal would be mined on two equal benches spanning the same distances, with at least 100 feet between benches.

- Low-quality overburden from adjacent mining areas or from stockpiles would be replaced in mined-out areas, in several layers or "lifts," along with ash and other solid waste from the gasification plant. Overburden judged suitable as a root medium would be placed in the topmost lift, to a depth of at least 8 feet.
- The replaced overburden or "spoil" would be graded to pre-determined contours, scarified ("ripped"), and covered with topsoil to a depth of 18 inches.
- The surface would be seeded, mulched, and reclaimed.

The above sequence is illustrated schematically in Figure 3.4-12. Stripping and backfilling would generally be a single continuous operation, with spoil transported from one end of a pit to the other by means of ramps and roads within or alongside the pit. These areas would assume a stair-step appearance; Figures 3.4-13 and 3.4-14 show typical pit configurations in the south and north mining blocks, respectively.

Disturbance Sequence. The maximum extent of surface disturbance in the Rochelle Mine permit area is summarized by mining year in Figure 3.4-15; the earliest disturbance is generally topsoil removal.

As Figure 3.4-15 shows, operations in year 1 would have extended only to the facilities area and to the mine access road and adjacent topsoil storage piles. In year 2, construction of a permanent diversion for Knapp Draw would have begun in the northwest corner of the South Block; an overburden stockpile location (OSP-2) would be cleared of salvageable topsoil; haul roads would be developed to link these areas with the initial topsoil storage area; and topsoil stripping



3-104

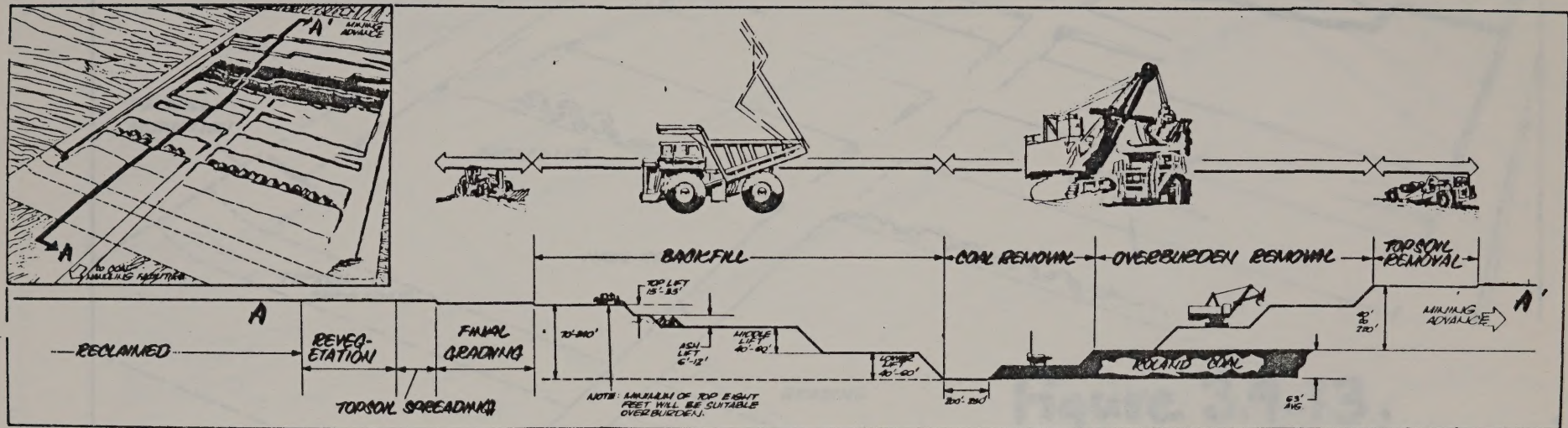


Figure 3.4-12. Typical Mining Sequence, Rochelle Mine (Schematic)



3-105

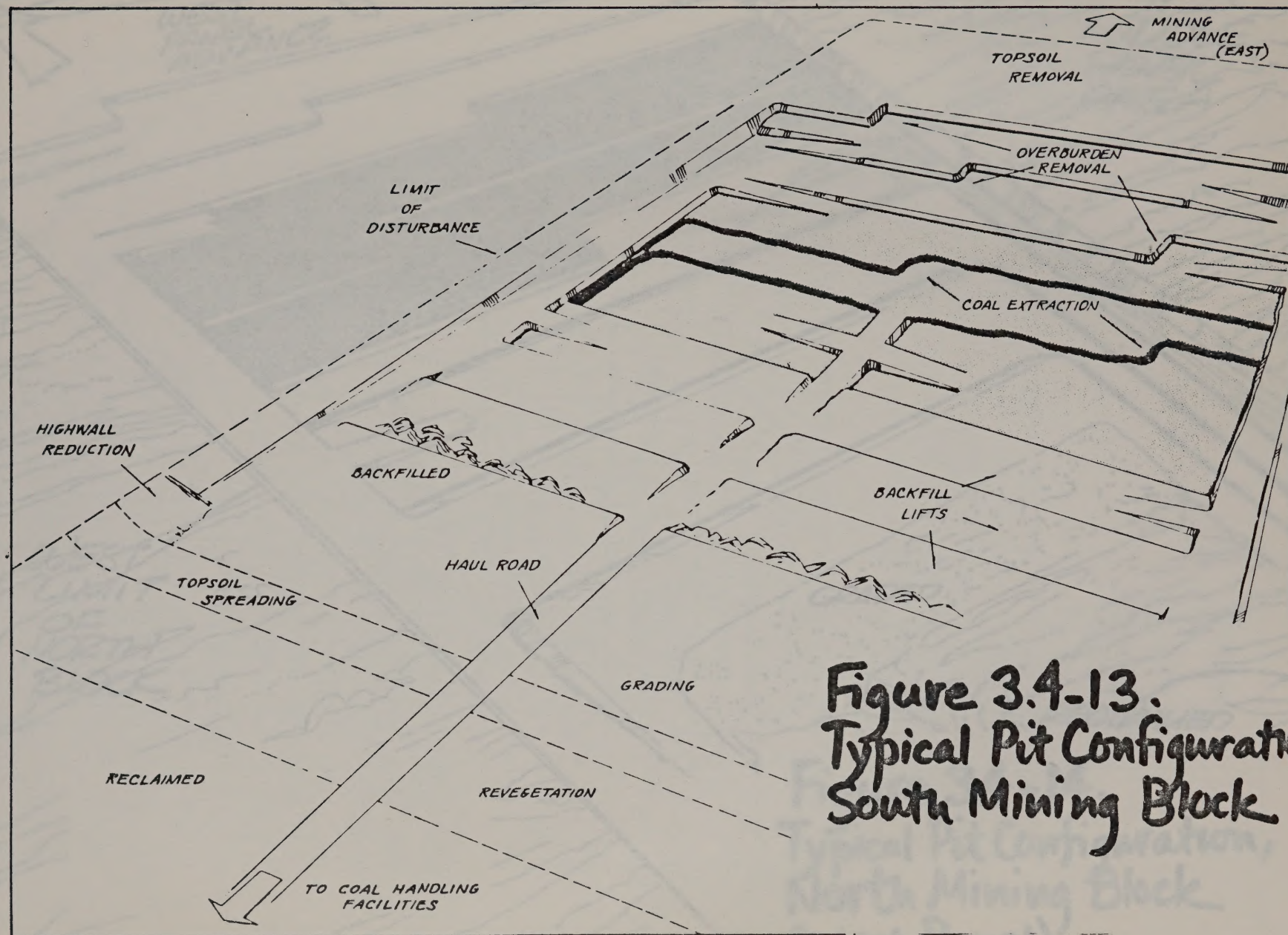


Figure 3.4-13.  
Typical Pit Configuration,  
South Mining Block



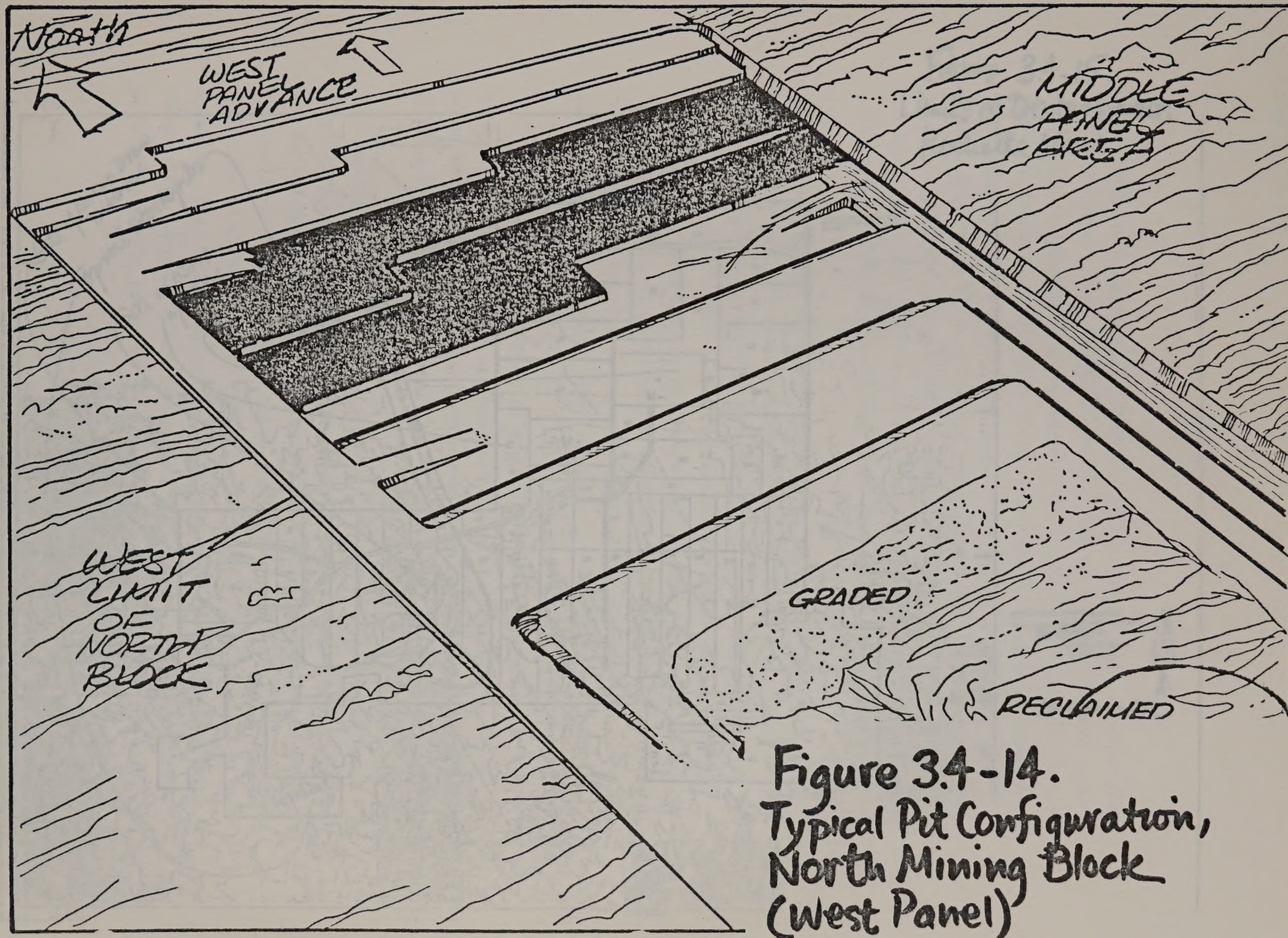
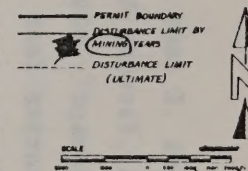
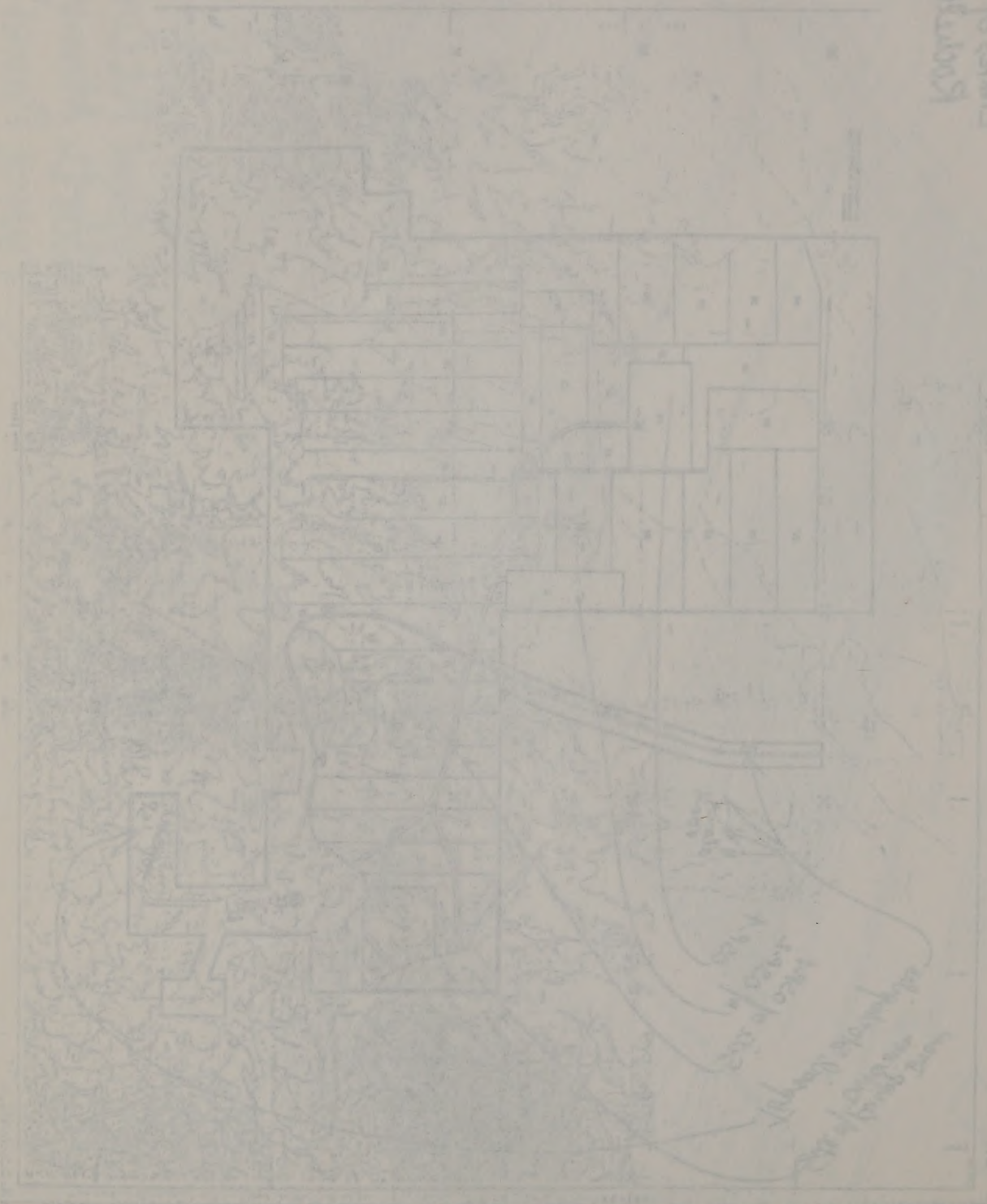




Figure 3.4-15.  
Limits of Disturbance,  
Rochelle Mine





Kootenai River  
 Village of Dabulpo  
 24-12

would begin over areas to be initially mined. In year 3, another overburden stockpile area (OSP-1) would be cleared of topsoil, and overburden removal would have commenced with the initial "boxcut" in the southwest corner of the South Block. By year 4, coal extraction would have begun and all mining operations would be advancing eastward through the South Block. In this year, overburden backfilling would also begin in the sections first mined, and as described in Section 3.4.4, reclamation would begin over mined areas by year 6, and would closely follow mining activities until operations are terminated.

As the South Block nears completion in year 22, coal extraction would begin in the southwest corner of the North Block. Since this area would have been previously excavated in years 14, 15, and 16, a second boxcut would be avoided by leaving the adjacent pit only partially filled, and temporarily reseeded. Overburden along the entire North Block-South Block interface would be handled a second time when the North Block is mined; temporary reclamation measures for this area are explained in Section 3.4.4.

Because the North Block is approximately 2 miles wide, it would be split into 3 segments or "panels," oriented north-south, which would be mined consecutively, progressing as shown in Figures 3.4-9 and 3.4-15.

During the entire mining process, a total of six overburden stockpiles would be developed in prearranged locations, and would grow and shrink depending on the relationship between excavated material and the area immediately available for backfilling. This procedure is explained in more detail in following sections, along with topsoil handling, coal handling, ash disposal, blasting procedures, and pit dewatering. Section 3.4.4 describes the reclamation process and post-mining management program.

would begin over areas to be initially mined. In year 3, another over-  
 burden removal area (025-1) would be cleared of topsoil, and over-  
 burden removal would have commenced with the initial "boxcar" in the  
 southwest corner of the South Block. By year 4, coal extraction would  
 have begun and all mining operations would be advancing eastward  
 through the South Block. In this year, overburden backfilling would  
 also begin in the section first mined, and as described in Section  
 3.4.4, reclamation would begin over areas by year 6, and would  
 closely follow mining activities until operations are terminated.

As the South Block reclamation begins in year 6, coal extraction  
 would begin in the southwest corner of the North Block. Since this  
 area would have been previously reclaimed in years 10, 12, and 16, a  
 second boxcar would be avoided by leaving the adjacent pit only par-  
 tially filled, and reclamation needed. Reclamation along the entire  
 North Block-South Block interface would be finished a second time when  
 the North Block is mined; temporary reclamation measures for this area  
 are explained in Section 3.4.4.

Because the North Block is approximately 3 miles wide, it would  
 be split into 3 segments or "panels," oriented north-south, which  
 would be mined consecutively, progressing as shown in Figures 3.4-3  
 and 3.4-11.

During the entire mining process, a total of six overburden  
 stockpiles would be developed in prescribed locations and would grow  
 and shrink depending on the relationship between excavated material  
 and the area immediately available for backfilling. This procedure is  
 explained in more detail in following sections, along with topsoil  
 handling, coal handling, and disposal, blasting procedures, and air  
 dust control. Section 3.4.4 describes the reclamation process and pre-  
 mining management program.

Mining Equipment. Table 3.4-9 lists the major equipment that would be needed for mining and reclamation activities during the first 5 years of operation. The use of the manufacturer's name is for illustrative purposes only, and does not signify any intent to use these specific brands or models.

Topsoil Removal, Handling, and Replacement

Before any area at the mine (other than a proposed topsoil stockpile site) is disturbed, topsoil suitable for use in reclamation would be removed to the depth specified in Figure 3.4-16. Suitability criteria are discussed in Chapter Two of the EIS. Whenever practical, the salvaged topsoil would be taken immediately to regraded backfill areas; in all other cases it would be stored at sites along the access road or in section 15, as shown in Figure 3.4-15.

Topsoil From Access Road. Material stripped from the roadway would be reserved, in stockpiles along the road, for redistribution over the reclaimed roadbed. Since these stockpiles would remain until the completion of all mining operations, they would be graded and seeded with quick-growing grass species, and fenced, for the life of the mine. Most topsoil from the roadway within the actual mining area would be stored in section 15, along with topsoil recovered during other construction activities and initial mining operations.

Topsoil From Facilities Area. All material stripped from the facilities area would be stored in section 15 for the life of the mine. Two years after the end of coal extraction, all structures would be dismantled. Following regrading of the area, the topsoil would be replaced for final reclamation.

Topsoil From Knapp Draw Permanent Diversion. Topsoil salvaged from the construction of the Knapp Draw diversion (refer to Section 3.4.2)

Minor Equipment. Table 1-4-9 lists the major equipment that would be needed for mining and reclamation activities during the first 5 years of operation. The use of the manufacturer's name is for illustrative purposes only, and does not signify any intent to use these specific brands or models.

Topsoil Removal, Handling, and Replacement

Before any area at the mine (other than a proposed topsoil stockpile area) is disturbed, topsoil within the area is reclamation would be removed to the depth specified in Figure 1-4-10. Subsoil strata are discussed in Chapter Two of the EIS. Wherever practical, the salvaged topsoil would be taken immediately to graded backfill areas; in all other cases it would be stored at sites along the access road or in section 15, as shown in Figure 1-4-11.

Topsoil From Access Road. Topsoil stripped from the roadway would be removed, in accordance with the road, for redistribution over the reclaimed crevices. Since these strip-mined would remain until the completion of all mining operations, they would be graded and seeded with native-growing grass species, and topsoil, for the life of the mine. Most topsoil from the roadway within the actual mining area would be stored in section 15, along with topsoil recovered during other construction activities and initial seeding operations.

Topsoil From Facilities Area. All material stripped from the facilities area would be stored in section 15 for the life of the mine. Two years after the end of coal production, all structures would be dismantled. Following regrading of the area, the topsoil would be replaced for final reclamation.

Topsoil From Waste Water Treatment Facilities. Topsoil salvaged from the construction of the waste water treatment (refer to Section 1-4-2)

TABLE 3.4-9

MINING AND RECLAMATION EQUIPMENT, ROCHELLE MINE  
(Initial Five-Year Period)

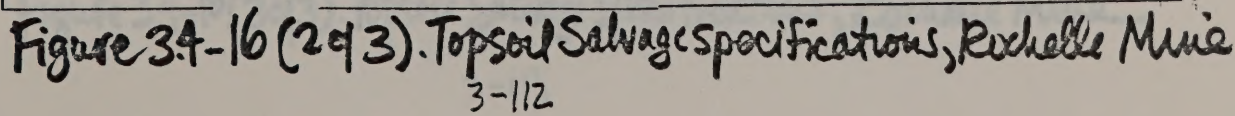
Item	Maximum Number Required
Bucyrus Erie 295B Coal Shovels	2
Bucyrus Erie 295B Overburden Shovels	2
Robbins RR 11 Drills	2
Ingersoll-Rand D-5000 Drill	1
120-Ton Rear-Dump Coal Haulers	15
150-Ton Rear-Dump Overburden Haulers	10
D9 Tractor Dozers	4
Clark 300HP Rubber-Tire Dozers	3
12-16 yd Front-End Loader	1
25-30 yd Twin Engine Scrapers	3
Cat 16 Motor Graders (Patrol)	3
16,000-Gallon Water Trucks	2
100-Ton Tractor with Low Boy	1
Ford F-600 Utility Trucks	3
Ford LNT 800 & 8000 Service Trucks	3
Link Belt HG-238A Crane (140 Tons)	1
Light Duty Vehicles	21
Fork Lift (10 Ton)	1
Farm Tractor with Reclamation Equipment	1
Utility Tractor/Backhoe	1
Cherry Pickers (15 Ton & 35 Ton)	2

Note: Manufacturer designation is given only for size-type explanation; any item may be replaced by a comparable model at the time of purchase.









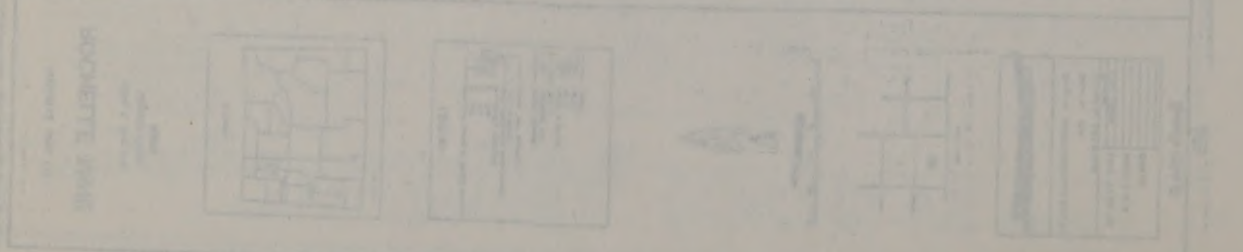
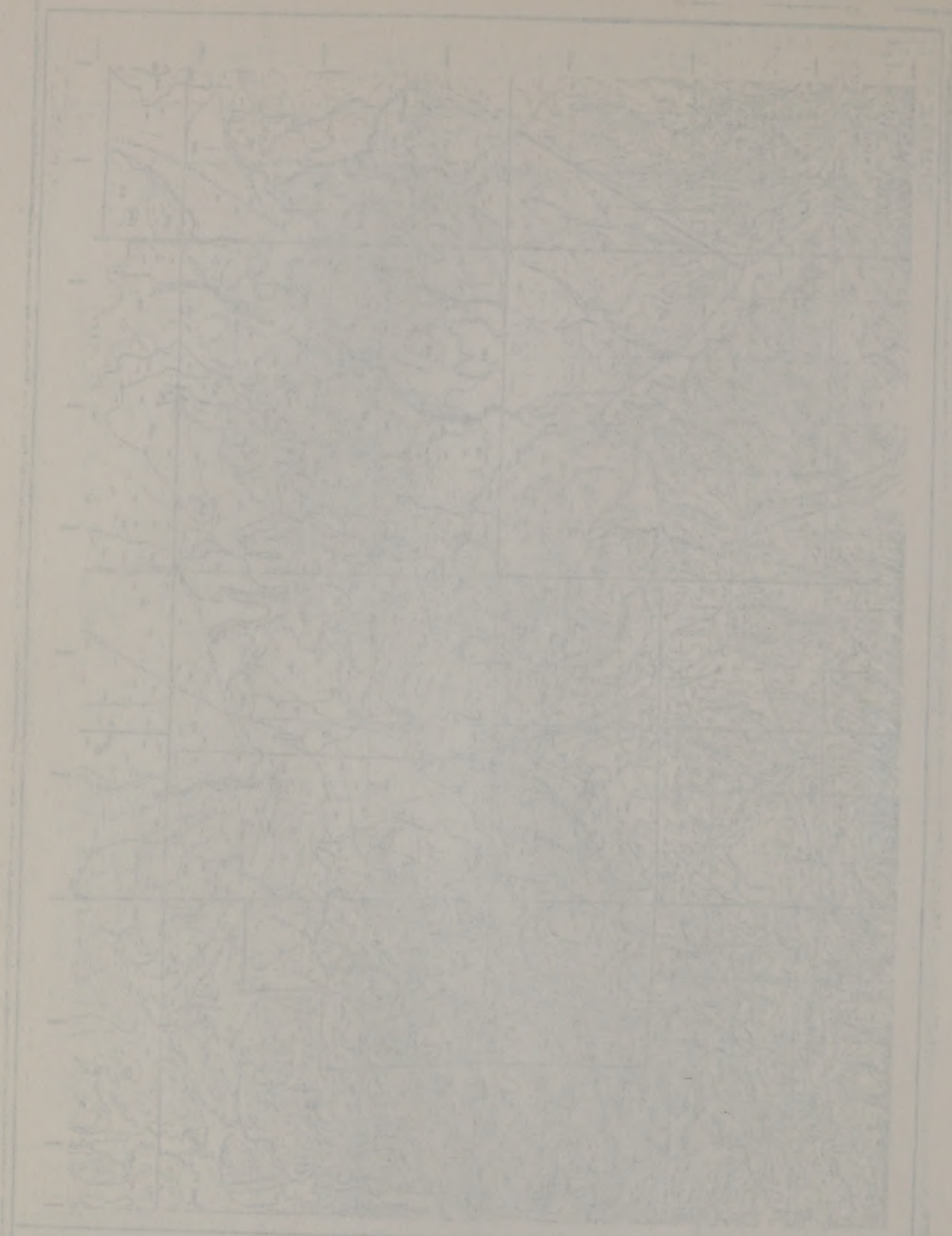
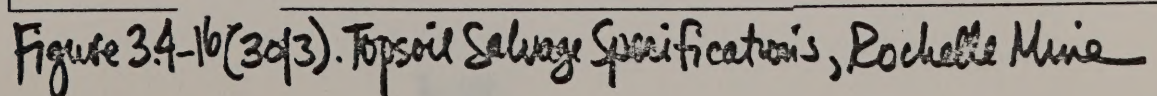


Figure 34-10 (2 of 3) Topographic Maps of Watersheds





would be stored in section 15. Because segments of this diversion would become permanent features in the post-mining topography, they must be topsoiled and seeded soon after construction. Consequently, much of the topsoil removed from the initial mining area would be placed immediately on the slopes and floodplain of this diversion. Although the diversion channel would be cut into bedrock, the guide channel would be armored with unconsolidated stream-layed soils collected from the original Knapp Draw Channel.

Clayey Soils From Playas. Although the clayey-textured soil which presently covers the playas in the northern area of the site is considered unsuitable as a growth medium, this material would be salvaged and stored in a separate stockpile in section 25. These clayey soils would be replaced as part of the playa reconstruction.

Topsoil From the Active Mining Area. During the initial phase of mining, the disturbance area would develop more rapidly than the area available for retopsoiling; therefore, most topsoil stripped in the early years of mining would be stockpiled in section 15. When mining has progressed to the point where the additional acreages stripped and backfilled in each year are approximately equal, topsoil would generally be placed on regraded spoil immediately after being stripped. Since reclamation would continue for two years after coal extraction has ended, retopsoiling of the final areas would depend upon stockpiled material.

Topsoil Salvage Procedure. Prior to topsoil recovery, the surface would be cleared of vegetation and recovery depth stakes would be set. The topsoil would generally be removed with self-loading scrapers and bulldozers. Where the material is of sufficient thickness and the A and B horizons are distinguishable, an attempt would be made to segregate the two horizons when the soil is to be immediately replaced

would be stored in section 15. Because segments of this diversion would become permanent features in the post-mining topography, they must be topogized and seeded soon after construction. Consequently, much of the topogized removed from the initial mining area would be placed immediately on the slopes and floodplains of this diversion. Although the diversion channel would be cut into bedrock, the guide channel would be armored with armorstone. The armorstone would be placed from the original heavy-duty armor.

Clayey Soils from River. Although the clayey-siltstone soil which presently covers the slopes in the northern area of the site is considered unsuitable as a growth medium, this material would be salvaged and stored in a separate stockpile in section 15. These clayey soils would be replaced as part of the pipe reconstruction.

Topsoil from the Initial Mining Area. During the initial phase of mining, the streambed area would develop more rapidly than the area available for revegetation. Therefore, most topsoil stripped in the early years of mining would be stockpiled in section 15. When mining has progressed to the point where the additional acreage stripped and backfilled in each year are approximately equal, topsoil would generally be placed in topogized areas immediately after being stripped. Since revegetation would continue for two years after each extraction has ended, stockpiling of the final areas would depend upon stockpiled material.

Topsoil from the Recovery Area. Prior to topsoil recovery, the surface would be cleared of vegetation and recovery duff. Spikes would be set. The topsoil would generally be removed with self-loading scrapers and bulldozers. Where the material is of sufficient thickness and the A and B horizons are distinguishable, an attempt would be made to segregate the two horizons when the soil is to be immediately replaced.

elsewhere. Soils less than 6 inches deep would be considered non-recoverable.

Topsoil Stockpiling Procedure. The following procedures would be used for all topsoil stockpiles:

- All slopes would be 3:1 or less;
- All stockpiles higher than 50 feet would be benched in 50-foot lifts with check dams to retard runoff;
- Bypass ditches would be constructed, where necessary, to divert runoff around stockpiles;
- Stockpiles would be clearly identified with signs at all access points (see Figure 3.4-7);
- All piles would be monitored for erosion, and where necessary, scarified, mulched, and seeded;
- All piles would have ditches, berms, or ponds to preserve topsoil and contain runoff.

Any stockpiles that would remain in place less than one year would not be revegetated; the surfaces of these piles would be left in a roughened condition to retard wind and water erosion. Topsoil stockpiles which remain in place longer than one year would be seeded with a quick-growing grass species.

Topsoil Replacement Procedure. An adequate quantity of topsoil would be recovered to subsequently replace an average of 18 inches of topsoil over all previously stripped areas. Whenever possible, the organic-rich top layer would be replaced in the upper lift. Before topsoil is spread on a regraded area, the surface would be scarified by deep ripping along the contour, to minimize erosion and instability. Graders and farm equipment would be used to finish topsoil replacement; the redistributed topsoil would be stabilized with mulch

elsewhere. Soils less than 6 inches deep would be considered non-  
recoverable.

Topsoil Reclamation Procedure. The following procedures would be  
used for all topsoil stockpiles:

- All slopes would be 3:1 or less;
  - All stockpiles higher than 20 feet would be benching in  
50-foot lifts with check dams to retard runoff;
  - Erosion ditches would be constructed, where necessary, to  
divert runoff around stockpiles;
  - Stockpiles would be clearly identified with signs at all  
access points (see Figure 1-2-7);
  - All piles would be monitored for erosion, and where  
necessary, scuttled, reshaped, and seeded;
  - All piles would have ditches, berms, or bands to prevent  
topsoil and contain runoff;
- Any stockpiles that would remain in place after they are used would not  
be revegetated; the surfaces of these piles would be left in a rough-  
ened condition to retard wind and water erosion. Topsoil stockpiles  
which remain in place longer than one year would be seeded with a quick-  
growing grass species.

Topsoil Reclamation Procedure. An adequate quantity of topsoil  
would be recovered to substantially replace the average of 18 inches of  
topsoil over all previously disturbed areas. Wherever possible, the  
original top layer would be replaced in the upper 12". Before  
topsoil is spread on a vegetated area, the surface would be scuttled  
by deep ripping along the contour, to maintain erosion and infiltration.  
Topsoil and tree seedlings would be used to finish topsoil  
replacement; the redistributed topsoil would be stabilized with mulch.

or a cover crop. Topsoil would not be used for stabilization of temporary disturbance; instead, stabilizing plant species would be seeded directly onto overburden or fill materials.

#### Overburden Removal, Handling, and Replacement

Overburden stripping would be performed in a stair-step manner, with similar operations occurring simultaneously on several benches. On each bench the overburden would be drilled and blasted as required, excavated by 20-yd<sup>3</sup> shovels or front-end loaders, loaded into 150-ton rear-dumping trucks, and hauled to a mined-out area or to a stockpile.

Overburden Classification and Sampling. The truck and shovel operation can selectively mine and place suitable overburden material; thus, material not suited to plant growth can be buried in the backfill. To ensure that suitable overburden is placed in the top 8 feet of the backfill, the operator would maintain a sampling program.

The overburden can, for this purpose, be classified as either scoria (some of which would be used for road surfacing); overburden chemically and physically suitable as a root-zone medium, as defined by the Wyoming Department of Environmental Quality; or unsuitable overburden. Scoria is easily recognized by its red color and its texture. The remaining overburden would be tested prior to mining by sampling one hole every 40 acres and analyzing the drill cuttings on 10-foot intervals.

The effectiveness of this overburden sampling procedure would in turn be assessed by a backfill sampling procedure, in which holes would be drilled in the replaced overburden, on 500-foot centers, just prior to topsoil placement. Each 8-foot sample hole would be split into two 4-foot intervals to be analyzed for boron, molybdenum, electrical conductivity, sodium absorption ratio, pH, and texture. If

or a cover crop. Topsoil would not be used for stabilization of low-  
power, high-moisture material. Stabilizing plant species would be seeded  
directly onto overburden or fill material.

Overburden Removal, Handling, and Reclamation

Overburden stripping would be performed in a single-step manner,  
with similar operations occurring simultaneously on several benches.  
On each bench the overburden would be drilled and blasted as required,  
excavated by 10-yd<sup>3</sup> shovels or front-end loaders, loaded into 100-ton  
test-dumping trucks, and hauled to a wind-sort area or to a stockpile.

Overburden Classification and Sorting The trash and gravel opera-  
tion can selectively mine and place suitable overburden material.  
Thus, material not suited to plant growth can be buried in the back-  
fill. To ensure that suitable overburden is placed in the top 6 feet  
of the backfill, the operator would maintain a sampling program.

The overburden can, for this purpose, be classified as either  
scoria (some of which would be used for road work) or overburden  
chemically and physically suitable as a root-zone medium, as defined  
by the Wyoming Department of Environmental Quality; or unsuitable  
overburden. Scoria is easily recognized by its red color and its  
texture. The remaining overburden would be tested before reusing by  
sampling one hole every 50 yards and analyzing the data on logs on  
10-foot intervals.

The effectiveness of this overburden sorting procedure would in  
turn be assessed by a backfill sampling procedure, in which holes  
would be drilled in the tapered backfill area, at 500-foot centers, just  
prior to topsoil placement. Each 3-foot depth hole would be split  
into two 4-foot intervals to be analyzed for pH, conductivity, elec-  
trical conductivity, sodium absorption ratio, pH, and texture. If

unsuitable overburden is found in the top eight feet of the regraded soil, the following steps would be taken:

- The area around the suspect hole would be sampled on a closer spacing;
- If the problem is related to pH, chemical amendments such as lime or fly ash would be added;
- The suspect area would be deep ripped and regraded; and,
- If none of the above solve the problem, the Wyoming Land Quality Division would be notified and an acceptable alternative procedure developed.

Overburden Removal. Overburden would be removed in benches with a maximum height of 50 feet; in general, the South Block would require three benches and the North Block four. Benches may be split to selectively handle material targeted by the overburden sampling program. Approximately 225 feet of working room would be maintained between each lift.

If blasting is required, procedures outlined in a later section would be followed. Loading would usually be by 20-yd<sup>3</sup> electric-powered shovels, into 150-ton capacity diesel-powered haulers.

The wide, slowly advancing pits in the South Block, 3,000 to 6,000 feet wide, would permit the development of a ramp system typified in Figure 3.4-13. The North Block would be excavated with narrower pits in thicker overburden, as described above; a typical pit and its ramp system is shown in Figure 3.4-14.

Figure 3.4-17 shows the sequence, by mining year, of overburden removal.

unavoidable overburden is found in the top eight feet of the overburden soil, the following steps would be taken:

- a The area around the suspect hole would be sampled on a closer spacing;
- b If the problem is related to the chemical constituents such as lead or fly ash would be added;
- c The suspect area would be deep ripped and regraded;
- d If none of the above solves the problem, the Wyoming Land Quality Division would be notified and an acceptable alternative procedure developed.

Overburden Removal. Overburden would be removed in benches with a maximum height of 30 feet. In general, the North Block would require three benches and the North Block four. Benches may be split to selectively handle material suggested by the overburden sampling program. Approximately 115 tons of working face would be maintained between each lift.

If blasting is required, procedures outlined in a later section would be followed. Loading would usually be by 30-ton capacity powered shovels, late 150-ton capacity diesel-powered haulers.

The wide, slowly advancing pits in the North Block, 3,000 to 4,000 feet wide, would permit the development of a ramp system typical in Figure 3.4-11. The North Block would be excavated with a lower pit in further overburden, as depicted above, a typical pit and its ramp system is shown in Figure 3.4-12.

Figure 3.4-13 shows the sequence of mining, by which part of overburden removal.

3-118

OSP-1: 3-12  
 OSP-2: 2-41  
 OSP-3: yrs. 9-42  
 OSP-4: 14-31  
 OSP-5: 16-41  
 OSP-6: 20-30

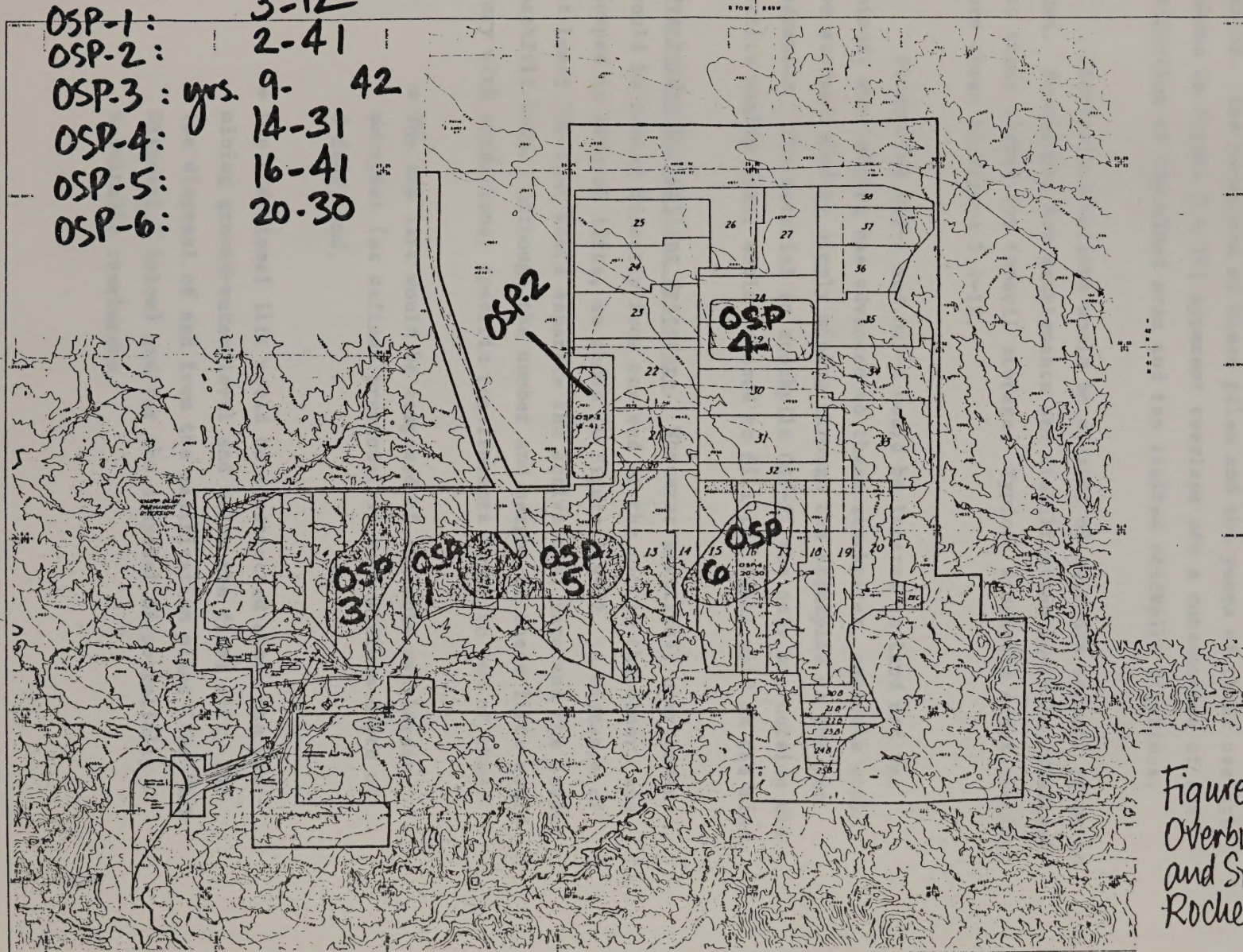


Figure 3.4-17.  
 Overburden Progression  
 and Stockpile Location,  
 Rochelle Mine



Overburden Stockpiling Procedure. Overburden not available for immediate backfilling would be stored in one of six overburden stockpiles. The locations of these piles and the years of their use are shown in Figure 3.4-17; apparent overlaps are a consequence of the migration of the mined area and the limited stockpile lifetimes.

Stockpile locations would be cleared of suitable topsoil prior to use. Procedures for maintenance and stabilization would be identical to those listed for topsoil storage. Typical stockpile cross sections are shown in Figure 3.4-18.

Stockpiles OSP-1 and OSP-4 would be located on land not yet mined; when mining has advanced to these stockpiles, rehandle would be accomplished by simply mining through the stockpile as the pit advances. The material in stockpile OSP-2, the only one outside the active mining area, would be used to fill the final void in the mine.

Overburden Backfilling Procedure. Whenever practical, overburden would be hauled directly from one end of the pit to the other, and dumped in several lifts, as shown in Figure 3.4-12. A distance of at least 200 feet would separate the active coal face and the lowest backfill lift. Although the number and height of these lifts would vary with conditions, specific requirements apply to two of them:

- The top lift would be composed of suitable overburden material (as defined previously), to a minimum depth of 8 feet; and,
- One additional lift would be constructed above the post-mining ground-water level and below the final lift, for the disposal of ash from the gasification plant (see "Ash Disposal," below) and for the disposal of potentially unsuitable overburden.

Overburden Stockpiling Procedure - Overburden not available for immediate backfilling would be stored in one of six overburden stockpiles. The locations of these piles and the years of their use are shown in Figure 3-4-1; apparent overlap was a consequence of the migration of the wind area and the limited stockpile lifetime.

Stockpile locations would be chosen to maintain suitable access to overburden for maintenance and stabilization would be identical to those listed for typical stockpile areas. Typical stockpile areas are shown in Figure 3-4-1b.

Stockpiles 001-1 and 001-2 would be located on land not yet mined; when mining has advanced to these stockpiles, materials would be removed by simply mining through the stockpile as the pit advances. The material in stockpile 001-2, the only one outside the active mining area, would be used to fill the final void in the mine.

Overburden Backfilling Procedure - Whenever practical, overburden would be hauled directly from one end of the pit to the other, and dumped in several lifts, as shown in Figure 3-4-2. A distance of at least 100 feet would separate the active coal face and the lower backfill lift. Although the number and height of these lifts would vary with conditions, specific requirements apply to two of them:

The top lift would be composed of suitable overburden material (as defined previously), to a minimum depth of 5 feet; and,

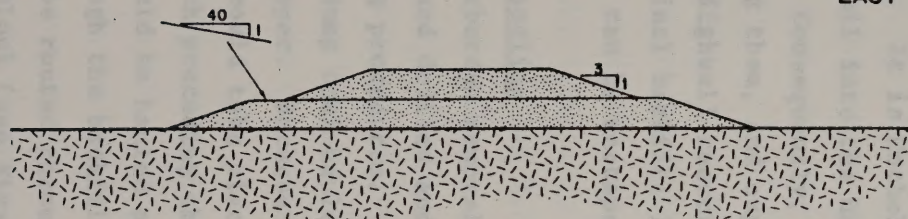
One additional lift would be constructed above the post-mining ground-water level and below the final lift, for the disposal of ash from the gasification plant (see "Ash Disposal," below) and for the disposal of potentially unsuitable overburden.

# TYPICAL CROSS SECTIONS OF OVERBURDEN STOCKPILES

SCALE 1"=200'

WEST

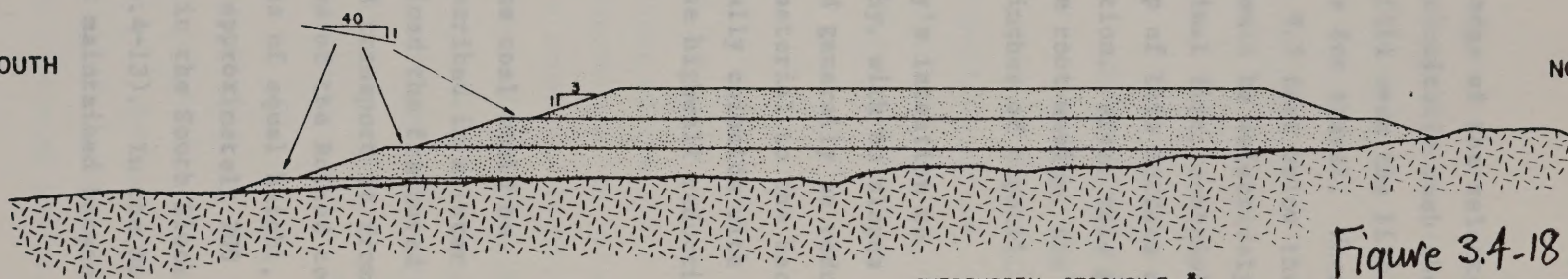
EAST



OVERBURDEN STOCKPILE #2

SOUTH

NORTH



OVERBURDEN STOCKPILE #1



Original Ground With Topsoil Removed

Stockpile Material

Figure 3.4-18.  
Typical Cross-Sections  
of Overburden  
Stockpiles,  
Rockelle Mine

3-120



Overburden haulers would back up near the edge of the selected lift and dump their loads. Bulldozers would periodically push the spoil over the edge of the dump, extending the fill over the lift below and keeping the surface level and suitable for travel. When the backfill is found by survey to be approximately 9.5 feet below the proposed post-mining surface elevation, spoil would be selectively dumped and roughly shaped by bulldozers. The final lift, containing only suitable overburden, would be formed on top of this surface and graded to 18 inches below the post-mining elevation. After this final lift has been sampled and verified as a suitable root medium, the surface would be deep ripped, and covered with 18 inches of topsoil.

Highwall Reduction. It is Rochelle Coal Company's intention to blend the shaped soil into the natural topography, with no slopes steeper than 5:1. Consequently, highwalls would generally be reduced by excavating along them, and exporting excess material to the backfill in the pit. Highwall reduction would normally coincide with placement of the final backfill lift, so that the highwall reduction area and the spoil can be reshaped as a unit.

#### Coal Removal and Handling

Following overburden removal, the top of the coal would be cleaned of waste, and drilled and blasted as described in a later section on blasting procedures. Shovels would load the fractured coal into 120-ton rear-dump coal haulers, which would transport it from the pit to the dump hopper. Because of the thickness of the Roland coal seam, these steps would take place on two benches of equal height, with the upper bench preceding the lower one by approximately 200 feet. The coal would be hauled out of the pits in the South Block via a center ramp through the backfill (see Figure 3.4-13). In the North Block, coal would be routed through end openings maintained between the panels of the block (see Figure 3.4-14).



Coal hauled from the mine would be discharged into a dump hopper and crushed to a 3-inch topsize. From there it would move to storage silos, and eventually to loadout facilities, as described in Section 3.4.1.

The proposed coal extraction schedule is shown in Figure 3.4-9.

#### Ash Disposal

Because the Rochelle Mine area terrain is relatively flat and well above the predicted post-mining ground-water level, it would provide a location for the disposal of fly ash, gasifier ash, and sludge from the proposed gasification plant. Properties of the plant's waste stream have been discussed in Section 3.3; the ash is not considered hazardous by EPA and Wyoming Department of Environmental Quality standards.

The initial output of ash from the plant would be stockpiled at the plant site for approximately 18 months, until adequate pit volume for disposal and reclamation had developed. Because of the ash's water content and the consequent difficulty of handling it in below-freezing weather, regular ash deliveries (via the proposed electric railroad) would only be made in warm weather. Ash would arrive, in cars designated for this purpose, and be emptied into a dump hopper beneath the railroad loop (see Figure 3.4-6). A conveyor would carry the ash to a silo near the coal dump hopper, where it would be loaded into empty coal haulers for delivery to the pit backfill area.

The proposed disposal method would be to dump the ash at the bottom of the top backfill lift, as shown in Figure 3.4-19. The ash depth at dumping locations would average 5 to 7 feet. Because the backfill lift would continue to advance when no ash was being dumped, the ash locations would be randomly discontinuous. Because ash would



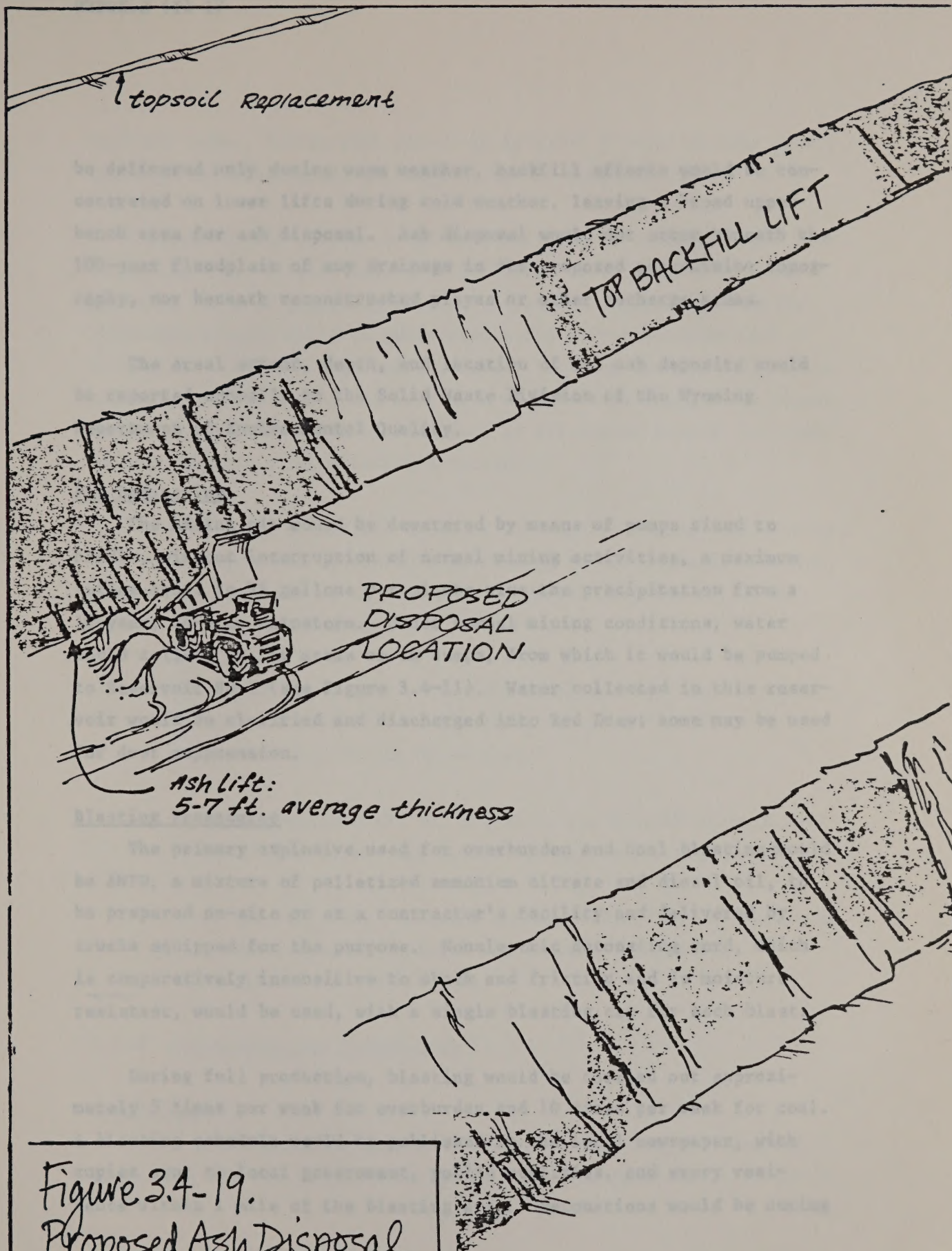


Figure 3.4-19.  
Proposed Ash Disposal  
Method, Rochelle Mine



be delivered only during warm weather, backfill efforts would be concentrated on lower lifts during cold weather, leaving a broad upper bench area for ash disposal. Ash disposal would not occur beneath the 100-year floodplain of any drainage in the proposed post-mining topography, nor beneath reconstructed playas or other recharge areas.

The areal extent, depth, and location of all ash deposits would be reported annually to the Solid Waste Division of the Wyoming Department of Environmental Quality.

#### Pit Dewatering

The mining pit would be dewatered by means of pumps sized to handle, without interruption of normal mining activities, a maximum inflow equal to 35 gallons per minute plus the precipitation from a 10-year, 24-hour rainstorm. Under normal mining conditions, water would collect in low areas or in sumps, from which it would be pumped to Reservoir SP-1 (see Figure 3.4-11). Water collected in this reservoir would be clarified and discharged into Red Draw; some may be used for dust suppression.

#### Blasting Procedures

The primary explosive used for overburden and coal blasting would be ANFO, a mixture of pelletized ammonium nitrate and diesel oil, to be prepared on-site or at a contractor's facility and delivered by trucks equipped for the purpose. Nonelectric detonating cord, which is comparatively insensitive to shock and friction and is moisture resistant, would be used, with a single blasting cap for each blast.

During full production, blasting would be carried out approximately 5 times per week for overburden and 10 times per week for coal. A blasting schedule would be published in the local newspaper, with copies sent to local government, public utilities, and every residence within 1 mile of the blasting area. Detonations would be during



daylight hours, during time intervals to total 4 hours or less in any one day. No blasting is anticipated during construction.

Access to blast areas would be controlled by entrance signs (see Figure 3.4-7). In addition, mine personnel would guard all access roads to the area beginning 10 minutes prior to detonation; access following a blast would be restricted until authorized personnel determined that safe conditions existed. Warning and all-clear siren signals, audible within one-half mile of the blast site, would sound; signal definitions would be displayed at all access points, and would be published with the blasting schedule.

All blasting operations would be in compliance with local, state, and federal laws and regulations pertaining to the storage, handling, preparation, and use of explosives. In particular, the following regulations would be observed:

- Wyoming Department of Environmental Quality, Land Division, Rules of Practice and Procedure, Chapter VI, "Blasting for Surface Coal Mining Operations."
- 30 CFR Sections 15, 16, 17, 55.6, and 77.1300 through 1308 (U.S. Mine Safety and Health Administration regulations).
- 27 CFR Part 181, "Commerce in Explosives," by the Bureau of Alcohol, Tobacco Products and Firearms of the U.S. Department of the Treasury.

#### 3.4.4 Abandonment and Reclamation

##### Introduction

The entire Rochelle Mine permit area is currently pasture and rangeland, and the proposed reclamation plan is intended to return it



to this use at the conclusion of mining operations; the area's value as wildlife habitat has also been taken into account. Reclamation objectives include: grading of spoils to a gently undulating topography with drainage patterns substantially the same as existing patterns (see Fig. 3.4-2); stabilization of remaining slopes to minimize wind and water erosion, and topsoil loss; establishment of a stable and diverse biotic community, both as range and as wildlife habitat.

Reclamation would be a continuing part of mining activity, following closely behind coal extraction itself, so that a relatively small fraction of the permit area (see Table 3.4-6) would be "open" at any time. As soon as coal was removed, overburden would be replaced, graded, scarified, and topsoiled; it is worth noting that procedures for classification, handling, and storage of topsoil and overburden, already discussed as "Mining Operations" (Section 3.4.3), are in fact integral parts of land reclamation. In what follows, the remaining aspects of this process will be discussed; these include the final topography, the revegetation process, decommissioning of facilities, and other post-production steps.

The reclamation plan would comply with the Federal Surface Mining Control and Reclamation Act of 1977, and with all other applicable federal and state laws and regulations. On private lands, all reclamation activities would be at the landowner's discretion.

#### Final Grading and Post-Mining Topography

Figure 3.4-20 shows the schedule for completion of grading, topsoiling, and reseeding, by mining year. The topmost backfill lifts in each year would be graded with bulldozers to a surface approximately 18 inches below the proposed final contours, and sampled for their suitability as a root medium. The surface would then be deep ripped, and topsoil would be applied and graded to a depth of 18 inches, with



3-127

Draw w/o  
Contours

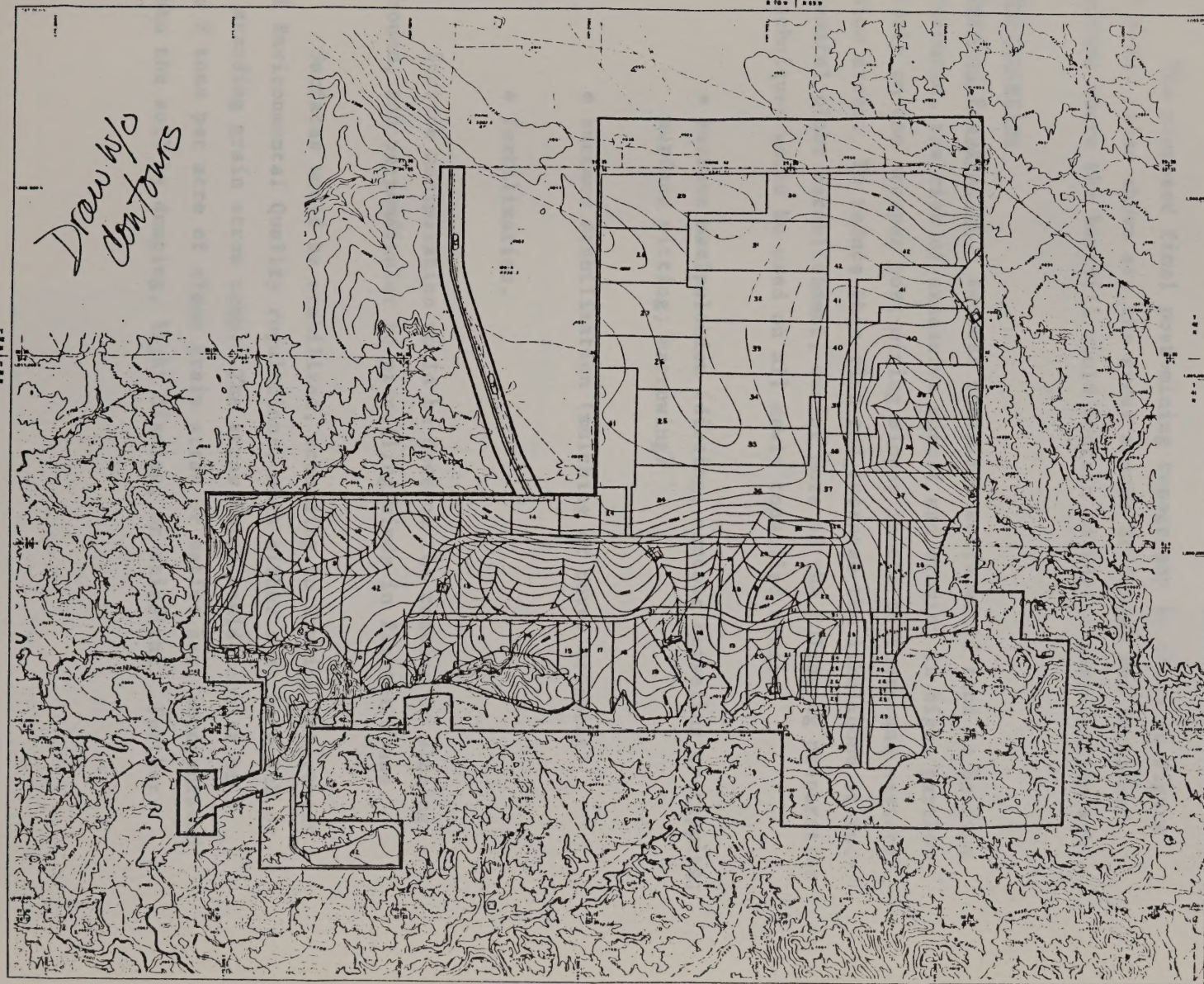


Figure 3.4-20.  
Reclamation  
Schedule,  
Rochelle Mine



the upper organic layers replaced at the surface where possible. During the final year of mining-associated operations (year 42), the final mine section and all roads and facilities areas would be graded and topsoiled.

The proposed final post-mining topography is shown in Figure 3.4-21. Also shown are the areas around drainages and reclaimed playas where the backfill would contain no buried gasification ash.

#### Revegetation

Seedbed Preparation. Because reclaimed soils would tend to be fine textured, the risk of excessive runoff and erosion is high, particularly on the steeper post-mining slopes in the southern and eastern mine areas. To reduce this risk and increase the likelihood of successful plant establishment, one or more of the following preparation techniques would be used on all newly topsoiled areas:

- surface manipulation (discing; contour chiseling or ripping; surface pitting; harrowing)
- surface stabilization (mulching or cover cropping)
- fertilization.

Surface manipulation would be done on the contour on sloping ground, and perpendicular to prevailing winds in flatter areas.

Surfaces would be stabilized, according to Wyoming Department of Environmental Quality regulations, with either a straw mulch or a standing grain straw crop. The straw mulch would consist of 1 to 2 tons per acre of clean grain straw or native hay, incorporated into the soil by dumping, light discing, or chiseling. Further



3-129

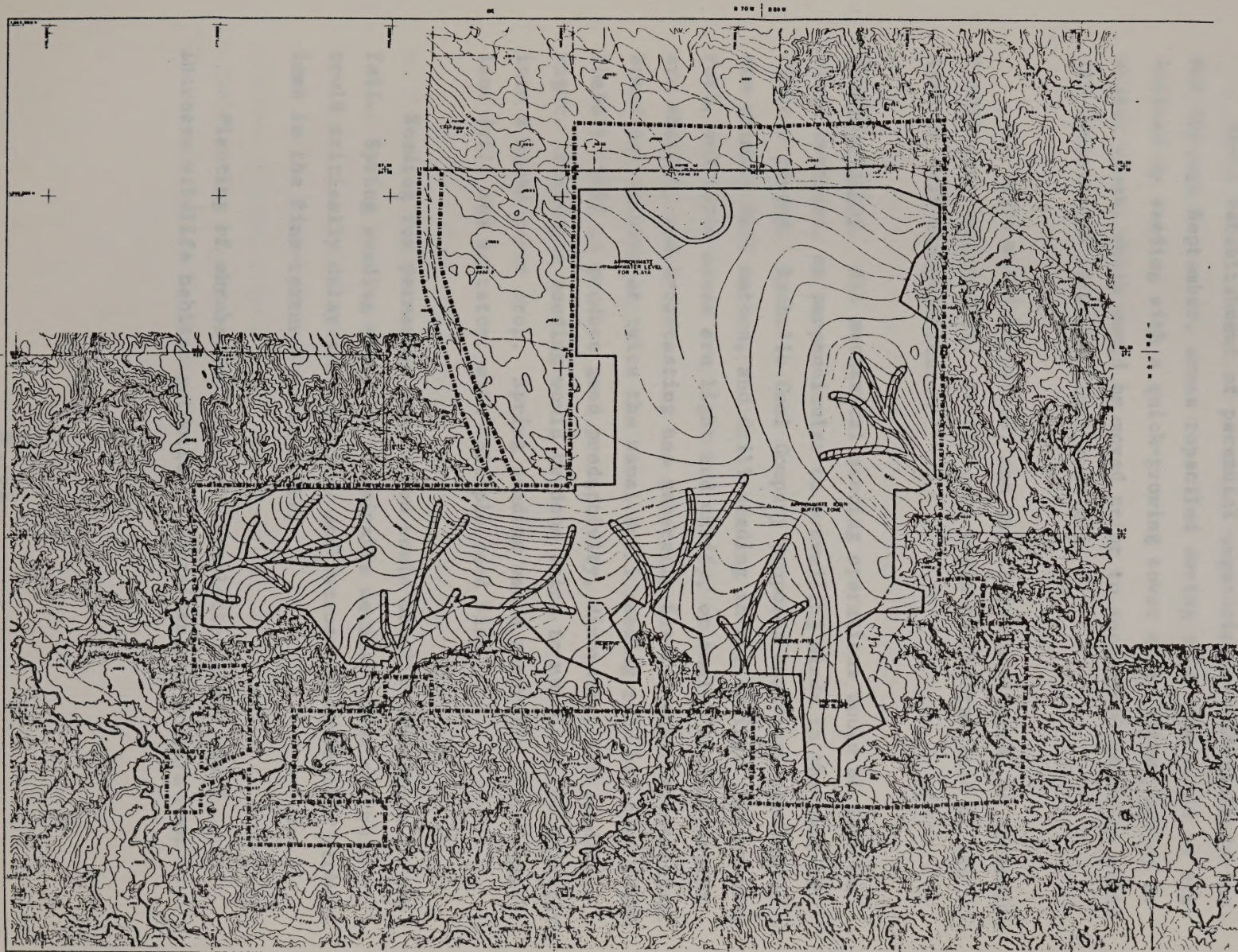


Figure 3.4-21.  
Post-Mining  
Topography,  
Rochelle Mine



stabilization, if needed, could be achieved with paper net mulch, straw with a tacking agent, jute netting, hydromulching, or rip-rap.

Since establishment of perennial vegetation is difficult during May through September, areas topsoiled during this time would be stabilized by seeding with a quick-growing cover crop, either barley or winter wheat, which would be moved prior to seed development to avoid its competition with the final seed mix.

All soils would be tested, and vegetation monitored, to determine fertilizer requirements. Fertilizers would be incorporated at the time of soil manipulation.

Seeding Method. All mechanical seeding operations would be done on slope contours, or perpendicular to prevailing winds in the case of flatter ground. Rochelle Coal Company proposes broadcast seeding as the primary fall method, and drill seeding in the spring. Many grass, forb, and shrub seeds are light and chaffy, or small; seeding depths are shallow, and broadcasting has generally favored their germination. Broadcast seeding at twice the usual drill seeding rate has been found (DePuit 1979) to produce good productivity, diversity, and seedling vigor. Broadcast seeding would be done prior to mulching, or directly into a mowed cover crop. Spring seeding would generally use a range-land drill and agitator, with multiple seed bins.

Seeding for permanent vegetation would usually take place in the fall. Spring seeding would be undesirable because thaws and rain could critically delay seeding time, and because of compaction problems in the fine-textured moist soils.

Planting of shrubs in "islands" in selected areas would increase wildlife habitat potential. Containerized or bare root



stock plantings are proposed for certain tree and shrub species. Transplanting of shrub species would be attempted.

Seed Mixes. The following distinct plant communities would be developed during reclamation processes:

- temporary revegetation
- drainage channel growth
- grass-rangeland
- shrub-grassland.

Table 3.4-10 lists the proposed seed mixtures for these communities, along with stubble crop for short-term stabilization.

All proposed species have been recorded on or near the mine site with the exception of the following: tall wheatgrass, Siberian wheatgrass, pubescent wheatgrass, Canada wildrye, big bluegrass, sideoats grama, flax, cicer milkvetch, alfalfa, antelope bitterbrush, winter wheat, thickspike wheatgrass, barley, creeping wildrye, and streambank wheatgrass. These species are adapted to the climate and soils of the area, and would provide a wider range of plant selection to ensure establishment of vegetation and increase the diversity of the new plant community.

Alfalfa, a nitrogen-fixing legume, has been included to help stabilize the topsoil stockpiles and to maintain or increase nitrogen levels in replaced topsoil. Yellow sweetclover, which already exists on site, is expected to establish naturally. Cicer milkvetch has been included in the permanent mix to provide a palatable legume that is somewhat drought tolerant; establishment would be limited to draws and other terrain features which collect moisture. The wheatgrasses and bluegrasses are proposed for early greening and to provide protection



TABLE 3.4-10

## SEED MIXES FOR THE ROCHELLE COAL MINE AREA

Seed Mix I: Temporary Reclamation		Seeding Rates <sup>a</sup> , #PLS/Acre <sup>b</sup>		
Species	Common Name	Topsoil Stock- piles	Active Roadways Rail Spur	Diversion Ditch
<u>Medicago sativa</u>	Alfalfa	2.0	---	2.0
<u>Melilotus</u> (alba-officinalis)	Sweetclover (white-yellow)	2.0	---	---
<u>Agropyron dasytachyum</u>	Thickspike wheatgrass	4.0	2.0	4.0
<u>Agropyron inerme</u>	Beardless bluebunch wheatgrass	1.0	2.0	---
<u>Agropyron riparium</u>	Streambank wheatgrass	2.0	6.0	4.0
<u>Agropyron smithii</u>	Western wheatgrass	4.0	4.0	6.0
<u>Agropyron trichophorum</u>	Pubescent wheatgrass	2.0	2.0	---
<u>Bouteloua gracilis</u>	Blue grama	0.5	2.0	---
<u>Elymus triticoides</u>	Creeping wildrye	0.5	2.0	4.0
<u>Oryzopsis hymenoides</u>	Indian ricegrass	2.0	---	---
<u>Poa ampla</u>	Big bluegrass	1.0	1.0	0.0
<u>Poa compressa</u>	Canada bluegrass	---	---	1.0
<u>Sporobolus airoides</u>	Alkali sacaton	---	0.5	1.0
<u>Sporobolus cryptandrus</u>	Sand dropseed	0.5	0.5	---

Seed Mix II:  
Drainage Channels

Species	Common Name	Seeding Rates <sup>a</sup> , #P.L.S./Acre <sup>b</sup>
<u>Agropyron dasystachyum</u>	Thickspike wheatgrass	2.0
<u>Agropyron elongatum</u>	Tall wheatgrass	2.0
<u>Agropyron riparium</u>	Streambank wheatgrass	4.0
<u>Agropyron smithii</u>	Western wheatgrass	4.0
<u>Agropyron trachycaulum</u>	Slender wheatgrass	2.0
<u>Bromus inermis</u>	Smooth brome	2.0
<u>Elymus triticoides</u>	Creeping wildrye	2.0
<u>Bouteloua gracilis</u>	Blue grama	1.0
<u>Astragalus cicer</u>	Cicer milkvetch	1.0
<u>Medicago sativa</u>	Alfalfa	1.0



TABLE 3.4-10 Continued

## SEED MIXES FOR THE ROCHELLE COAL MINE AREA

Seedling Mix II: Drainage Channels		
Species	Common Name	Seedlings/Acre
<u>Populus sargentii</u>	Plains cottonwood	15
<u>Populus lanceolata</u>	Narrowleaf cottonwood	15
<u>Prunus americana</u>	American plum	25
<u>Prunus virginiana</u>	Common chokecherry	10
<u>Salix</u> spp.	Willow	50
<u>Shepherdia argentea</u>	Silver buffaloberry	25
<u>Scirpus acutis</u>	Tule bulrush	Transplant
<u>Typha latifolia</u>	Common cattail	Transplant

Seed Mix III:  
Primary Reclamation Mix (Grass Rangeland)

Species	Common Name	Seeding Rates, <sup>a</sup> #P.L.S./Acre <sup>b</sup>
<u>Astragalus cicer</u>	Cicer milkvetch	1.0
<u>Medicago sativa</u>	Alfalfa	1.0
<u>Agropyron dasystachyum</u>	Thickspike wheatgrass	2.0
<u>Agropyron inerme</u>	Beardless bluebunch wheatgrass	2.0
<u>Agropyron riparium</u>	Streambank wheatgrass	2.0
<u>Agropyron smithii</u>	Western wheatgrass	3.0
<u>Agropyron trachycaulum</u>	Slender wheatgrass	2.0
<u>Andropogon scoparius</u>	Little bluestem	1.0
<u>Bouteloua curtipendula</u>	Sideoats grama	1.0
<u>Bouteloua gracilis</u>	Blue grama	1.0
<u>Calamovilfa longifolia</u>	Prairie sandreed	0.5
<u>Elymus triticoides</u>	Creeping wildrye	0.5
<u>Oryzopsis hymenoides</u>	Indian ricegrass	2.0
<u>Sporobolus airoides</u>	Alkali sacaton	tr. <sup>c</sup>
<u>Sporobolus cryptandrus</u>	Sand dropseed	tr. <sup>c</sup>
<u>Linum lewisii</u>	Lewis flax	0.2
<u>Atriplex canescens</u>	Four-wing saltbush	0.5
<u>Ceratoides lanata</u>	Winterfat	0.5
<u>Poa ampla</u>	Big bluegrass	0.5



TABLE 3.4-10 Concluded  
SEED MIXES FOR THE ROCHELLE COAL MINE AREA

Shrub-Grassland Complex Seeding:  
Seed Mix III, plus six or more  
of the following at a rate of 300/acre

Species	Common Name	Seedlings
<u>Artemisia frigida</u>	Fringed sagewort	0-50
<u>Artemisia ludoviciana</u>	Louisiana sagewort	0-50
<u>Artemisia tridentata</u> (v. <u>Wyomingensis</u> )	Big sagebrush	0-50
<u>Atriplex canescens</u>	Four-wing saltbush	0-50
<u>Atriplex gardneri</u>	Gardner's saltbush	0-50
<u>Purshia tridentata</u>	Antelope bitterbrush	0-50
<u>Rhus trilobata</u>	Skunkbrush sumac	0-50
<u>Ribes cereum</u>	Wax current	0-50
<u>Rosa woodsii</u>	Wood's rose	0-50
<u>Symphoricarpus albus</u>	Common snowberry	0-50
<u>Symphoricarpus occidentalis</u>	Western snowberry	0-50

Standing Stubble Crop or Off-Season Planting  
(Erosion Control)

Barley	Spring Drill Seeding	30.0 #P.L.S./Acre (60.0 #P.L.S./Acre, Broadcast)
Winter	Fall Drill Seeding	30.0 #P.L.S./Acre (60.0 #P.L.S./Acre, Broadcast)

<sup>a</sup>Broadcast seeding rates are twice the tabulated values.

<sup>b</sup>#P.L.S./Acre = Pounds Pure Live Seed Per Acre.

<sup>c</sup>tr = trace



in the drainage channels where runoff may occur; they also replace needlegrasses (Stipa, spp.), deleted at the specific request of John Dilts, Jr. (ranch operator). The needlegrasses, while being excellent cool-season native grasses and well suited for reclamation purposes, may cause damage to the wool value of sheep, and may cause severe irritation to the eyes, gums, and other soft tissues. Smooth brome (Seed Mix II) would be used along drainage channel disturbances where a lush, quick-growing, sod-forming grass is desired.

Potential seeding problems may exist with many shrub species. Fourwing saltbush must be dewinged, and the long silky hairs on winterfat seed need to be removed to facilitate drill seeding. Mixed results have been obtained while trying to establish big sagebrush from seed. Antelope bitterbrush would be tested on site; if results prove favorable, bitterbrush would be used on all appropriate sites. Since many of these problems would inhibit successful shrub establishment from seed, Rochelle Coal Company proposes the use of containerized tree and shrub seedlings to complement seeding and enhance shrub establishment.

Rochelle Coal Company proposes to establish test plots for evaluation of the proposed seed mixes. Initially, test plots would be established along road cuts and fills, sediment pond embankments, or other areas of early reclamation. While most of the grass species have been used for reclamation purposes in the past, the use of winterfat and bitterbrush is still somewhat experimental. The feasibility of transplanting existing shrubs would also be evaluated.

Because of the scarcity of available water in the permit area, revegetated areas would not be irrigated.



Substitute Species. Due to fluctuating seasonal production, variable demand, and unsteady or limited commercial availability, various grasses might not be available for reclamation purposes. Therefore, the substitutions or additions listed in Table 3.4-11 are proposed where necessary:

Playa Reclamation. A playa would be reclaimed in the northern part of the mine area. Clay soils present in several existing playas would be saved in order to reproduce the unique playa soil conditions. After shaping of the reclaimed playa area has taken place, the salvaged clay soil would be replaced and the area seeded to western wheatgrass (Agropyron smithii) and several species of bluegrass (Poa spp.).

#### Wildlife Plan

To develop potential wildlife habitat in the post-mining land use, several measures have been considered. As mining progresses, rocks and boulders would be piled on the reclaimed ridges to provide cover for small mammals, rodents, and reptiles, and perching sites for raptors and other bird species. One-half of the disturbed surface would be seeded as a shrub-grassland community to provide winter and fall habitat, and to provide emergency food sources for livestock in the winter. Shrub groupings ("islands") would be distributed throughout the area. Six different tree or shrub species would be planted along drainageways to provide additional habitat and nesting sites. Exclusion fencing would keep all big game species from dangerous mine areas while it protected newly seeded areas. No fences would be constructed along the proposed conveyor spur; consequently, wildlife movement would not be impeded there.

The following specific measures regarding eagles and other raptors would be taken:



TABLE 3.4-11

## SUBSTITUTE SEED SPECIES

Species	Would Replace (All or Part)
<u>Agropyron inerme</u>	<u>Agropyron spicatum</u> or <u>Agropyron trachycaulum</u>
<u>Festuca ovina</u> var. <u>duriuscula</u>	<u>Elymus canadensis</u> or <u>Agropyron</u> spp.
<u>Koeleria cristata</u>	<u>Agropyron</u> spp. or <u>Poa ampla</u>
<u>Poa sandbergii</u>	<u>Poa ampla</u> and <u>Agropyron</u> spp.
<u>Calamovilfa longifolia</u>	<u>Sporobolus</u> spp.



- Power lines associated with the Rochelle Mine property would be constructed in accordance with REA Bulletin Fl-10, "Power-line Contacts by Eagles and Other Large Birds."
- A golden eagle (Aquila crysaetos) nest is located just off the permit area in the NE1/4 of sec. 15, T. 41 N. R. 70 W. Mining activity would be timed for minimum disturbance if a nesting pair was using this nest. Alternatively, if data from the Powder River Basin eagle study, in which Rochelle Coal Company is a participant, were to show that the nest should be moved, the company would make the necessary Federal and State arrangements to do so.
- Any harassment or destruction of eagles or their nests would be immediately reported to the U.S. Fish and Wildlife Service Law Enforcement Division.

Two aerial flights (early August and early February of \_\_\_\_ ) would be made to determine summer and winter big game occurrence, distribution, and habitat affinity in a 70-square-mile census area. Sex and age ratios would be obtained for all big game species observed during the August census. Total herd size and the number of bucks would be recorded during the February flight. Any incidental observation of other wildlife species would also be recorded.

#### Decommissioning and Final Reclamation

Following the completion of mining, all facilities and equipment within the permit area would be dismantled. Nonsalvageable items such as lumber, insulation, conduit, oil drums, and plasterboard would be demolished and buried at least 5-feet deep. Concrete rubble would be placed at rock pile sites. Power lines and poles, above-ground piping, fence wire and posts, and the like, would be salvaged.



Haul roads would be recontoured, topsoiled, and seeded with Seed Mix III (See Table 3.4-10); unless the future landowner were to make a bonafide request to the contrary, the mine access road would be similarly reclaimed. Facilities sites would be recontoured, topsoiled, and seeded with Seed Mix III. After all other areas had been reclaimed and had undergone the observation period for determining reclamation success, the ponds and access roads to the ponds would be rough graded and topsoiled. Seed Mix II would be used in drainage-ways, and Seed Mix III on uplands disturbed by the access roads.

#### Mining and Post-Mining Management

The ongoing land management program at the Rochelle Mine would attempt to establish a self-sustaining vegetation cover on all mine disturbances, and return all lands to their pre-mining use, at production levels equal to or exceeding their original values. Presently the area is rangeland, and antelope and deer use the area year round. Management practices would include:

- fencing to defer grazing
- weed and, if necessary, insect control
- spot reseeding, if necessary
- gradual return to grazing
- rill and gully erosion control.

Once an area has been seeded, travel and grazing would be prohibited by means of fencing until vegetation had stabilized, which would take approximately 3 years in the case of permanent reclamation. Fences for grazing deferment would be removed upon proven establishment of vegetation. Topsoil stockpiles would be fenced to prevent trampling, which could increase erosion potential; sediment ponds would be fenced to reduce "bogging" by livestock or wildlife. Other



hazardous areas would be fenced where appropriate. Fence for these purposes would have the following design:

- open, 0 to 1 inch from ground (at post)
- sheeptight fence, 1 to 27 inches
- barbed wire, 31 and 42 inches.

The conveyor corridor would not be fenced, leaving antelope movement and migration unimpeded.

It is intended that weeds be controlled mechanically, through proper seedbed preparation, use of clean mulch, and mowing. If chemical weed or insect control is necessary, it would be carried out by licensed personnel, and with DEQ and local Weed and Pest Control District approval.

Areas that do not establish adequate cover would be reseeded, with consideration given to alternative preparation, seeding techniques, and seed mixtures.

After a sufficient acreage has been reclaimed to constitute a viable grazing unit, and after it has been determined that the vegetation there could sustain grazing, Rochelle Coal Company would submit a grazing plan to the DEQ. Approval would depend on the vegetation being self-sustaining and capable of supporting the intended land use.

Rochelle Coal Company has posted a reclamation bond as part of its application to the Wyoming Department of Environmental Quality (DEQ) for a permit to mine. Should the above reclamation plans fail, and should Rochelle choose not to begin the reclamation process again, this bond would be forfeited to the DEQ Division of Land Quality, who would assume responsibility for reclamation success.



### 3.5 RAILROAD

#### GENERAL DESCRIPTION

WyCoalGas, Inc., proposes to construct and operate an electrically-powered single-track main line railroad, extending approximately 40 miles from a rail spur at the Rochelle Mine (T. 41 N., R. 70 W., sec. 16) to the plant site (T. 35 N., R. 70 W., sec. 34). The railroad route is shown in Figure 3.5-1. Pertinent design parameters are listed in Table 3.5-1.

Three passing sidings approximately 2 miles in total length, and several minor sidings would handle disabled railcars. A 16-foot wide limited-access maintenance road would parallel the railroad; this road would not be used as a means of public or work force transportation.

The proposed railroad right-of-way would have approximately 16 crossings of unimproved and graded dirt roads, all lightly used for access to ranches and oil fields. Crossings at private and public roads would be designed to maximize safety to vehicular traffic, and would be either grade crossings with warning signs, grade crossings with signals and automatic gates, or separated grade crossings. Each crossing would conform to county and/or state requirements for public roads and to agreements negotiated with landowners for private roads. Numerous stock crossings would be provided, in the form of large culverts, underpasses, or separated grade crossings; types of crossings would depend on topography, frequency of use, and the existence of other crossing facilities in the adjacent highway and railroad.

Culverts would be installed at all stream crossings. Appendix B is a listing of all stream crossings by the proposed railroad and other project components.



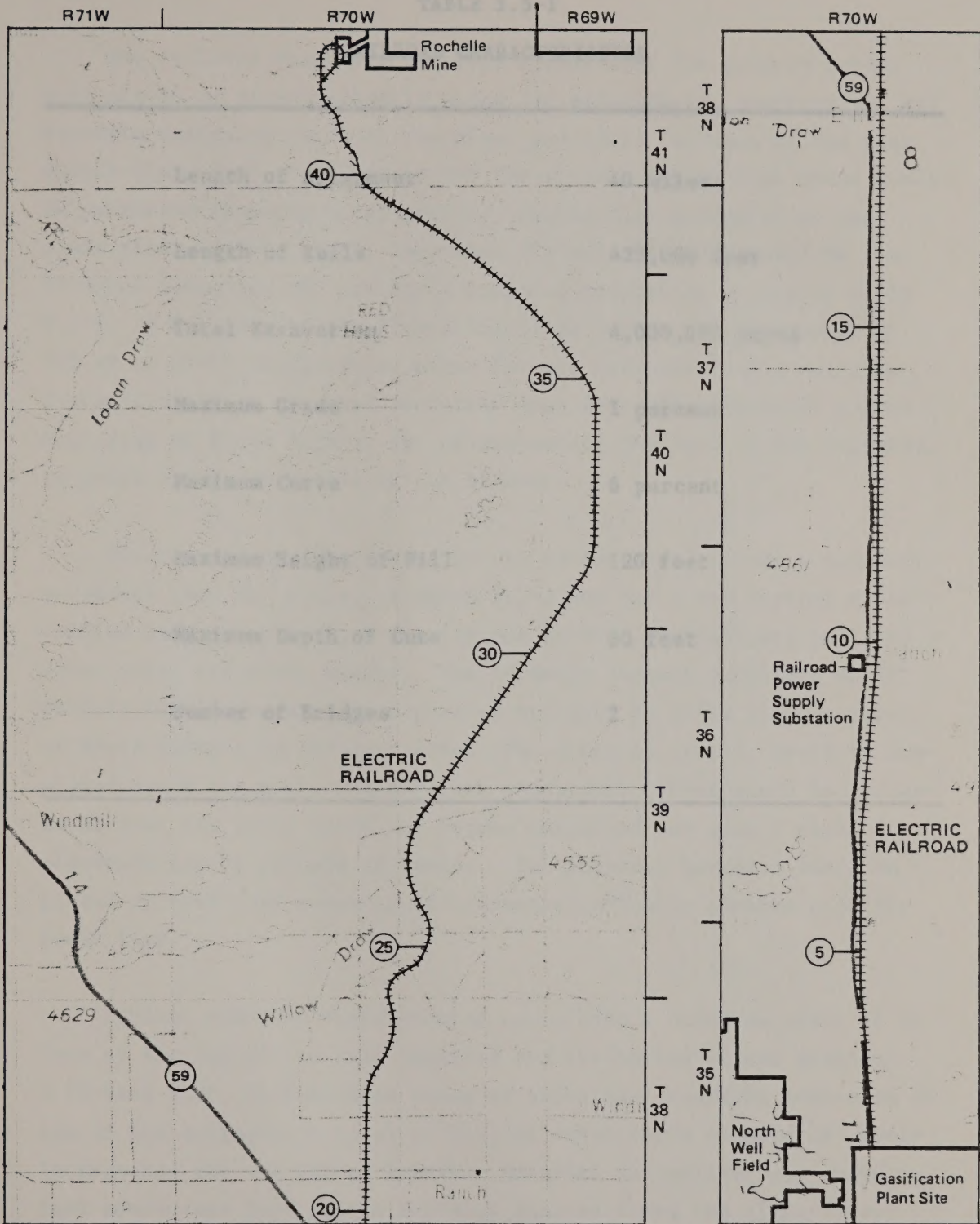


Figure 3.5-1  
COAL TRANSPORTATION RAILROAD



TABLE 3.5-1

## RAILROAD CHARACTERISTICS

The railroad would use electric locomotives for primary power, with diesel or diesel-electric units for maintenance, emergencies, and possible switching needs at the plant and mine. Because of the peak single-phase power for the system, additional power would be purchased from the local utility, rather than generated at the plant site.

Length of Alignment	40 miles
Length of Rails	425,000 feet
Total Excavation	4,000,000 yards
Maximum Grade	1 percent
Maximum Curve	6 percent

Power would be transmitted through a catenary suspended over the rails. Figures 3.5-2 and 3.5-3 are typical cross-sections of the railroad showing the roadbed, ballast, ties, rail, and power supply. The catenary support structure would include 16 bridges perched design 2 to avoid electrocution of birds landing on the structure. The electric circuit would be completed using the rails and a return conductor. These would be grounded so that the rails would not become energized and pose a risk of electrocution to animals or humans. Two physical barriers would be placed at each road crossing to guarantee vehicular clearance of the power line.

Typical railroad configuration would have a subgrade width of 25 feet at the top of the fill sections and the bottom of cut sections. A 12-inch deep, 25-foot wide layer of subballast would be compacted on top of the subgrade; a total of 113,000 cubic yards of material would be required for the entire length. Material for ballast and subballast would come from scoria deposits located along the right-of-way and at the Nochalla Mine. The primary ballast would consist of a



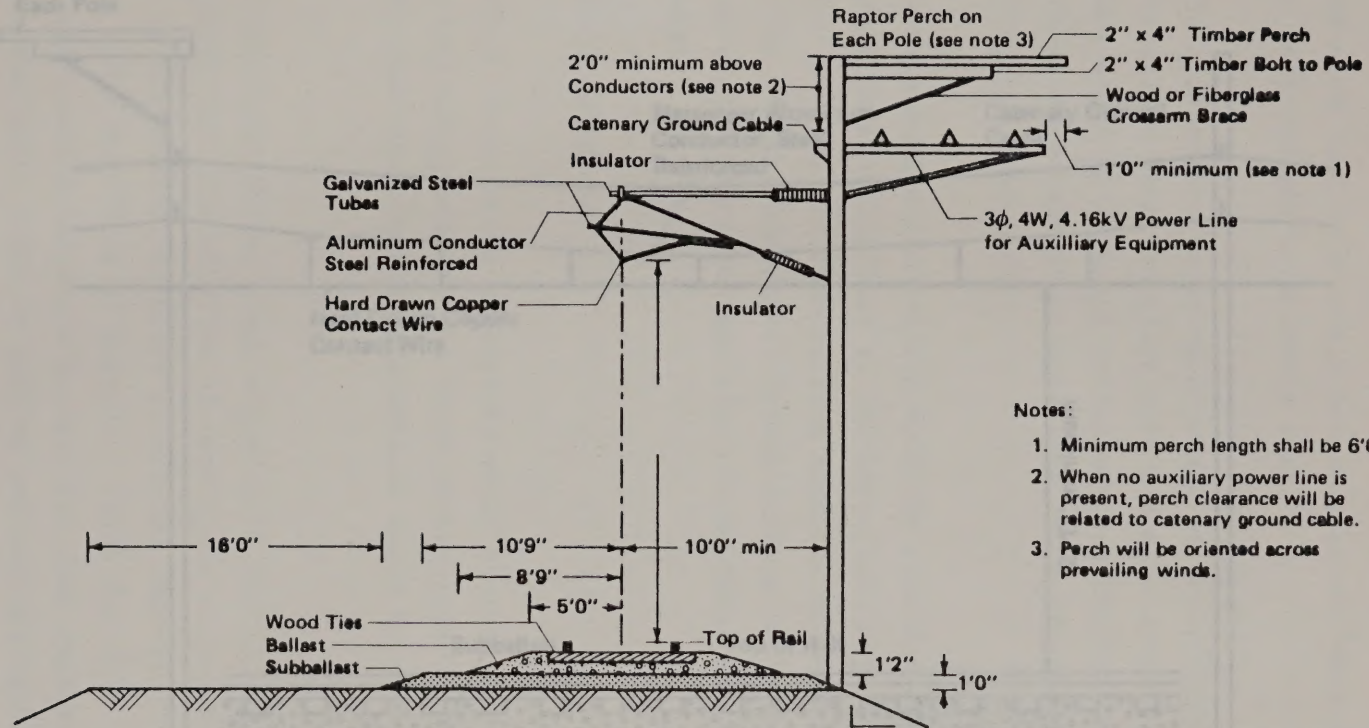
The railroad would use electric locomotives for primary power, with diesel or diesel-electric units for maintenance, emergencies, and possible switching needs at the plant and mine. Because of the peak single-phase load requirements for the system, operational power would be purchased from the local utility, rather than generated at the plant site. A substation, less than 1/4 acre in area, would be constructed alongside the utility's proposed substation (S 1/2 of T. 35 N., R. 70 W., sec. 4; see Figure 3.5-1) to convert 3-phase power at 230 kV to 50-kV single-phase power for the railroad. This would be transmitted by an overhead conductor line from the substation on the west side of State Highway 59, approximately 800 feet to the railroad, adjacent to the east side of the highway.

Power would be distributed to the locomotives through a catenary suspended over the rails. Figures 3.5-2 and 3.5-3 are typical cross-section and side elevation showing the roadbed, subballast, ballast, ties, rail, and power supply. The catenary support structure would include insulating parts and perches designed to avoid electrocution of birds landing on the structure. The electric circuit would be completed using the rails and a return conductor. These would be grounded so that the rails could not become energized and pose a risk of electrocution to animals or humans. Two physical barriers would be placed at each road crossing to guarantee vehicular clearance of the power line.

Typical railroad configuration would have a subgrade width of 25 feet at the top of the fill sections and the bottom of cut sections. A 12-inch deep, 25-foot wide layer of subballast would be compacted on top of the subgrade; a total of 115,000 cubic yards of material would be required for the entire length. Material for ballast and subballast would come from scoria deposits located along the right-of-way and at the Rochelle Mine. The primary ballast would consist of a



3-145



Notes:

1. Minimum perch length shall be 6'0".
2. When no auxiliary power line is present, perch clearance will be related to catenary ground cable.
3. Perch will be oriented across prevailing winds.

Figure 3.5-2  
TYPICAL CROSS SECTION OF RAILROAD



3-146

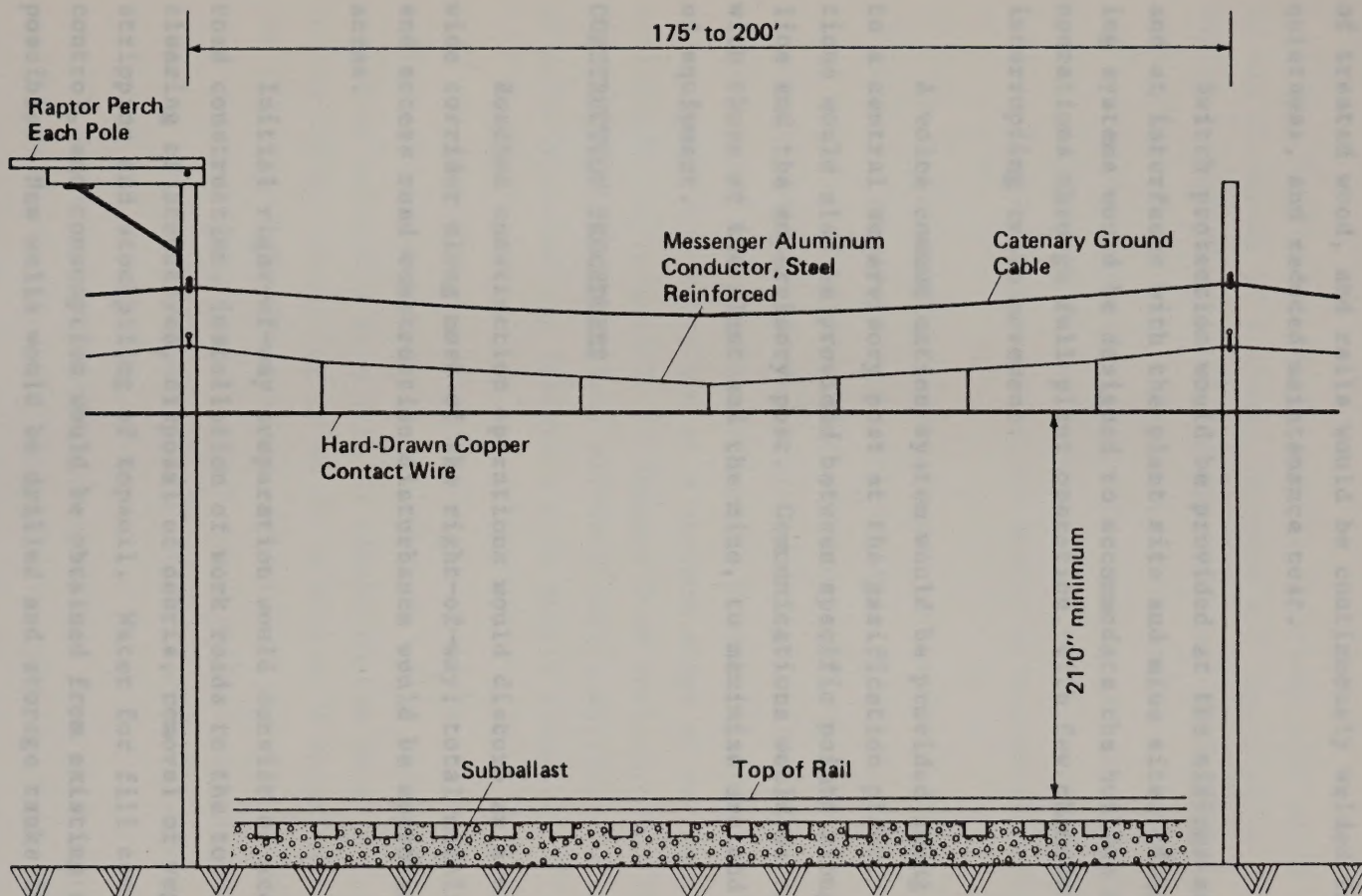


Figure 3.5-3  
TYPICAL SIDE ELEVATION



14-inch layer of crushed rock, 8 inches deep below the ties and 6 inches deep between the ties. The 6-inch by 8-inch ties would be made of treated wood, and rails would be continuously welded for stability, quietness, and reduced maintenance cost.

Switch protection would be provided at the sidings as required and at interfaces with the plant site and mine site. Track signaling systems would be designed to accommodate the buildup of train operations through full plant operation, with few changes and without interrupting train movement.

A voice communication system would be provided among trains, and to a central supervisory post at the gasification plant. Communications would also be provided between specific points along the rail line and the supervisory post. Communications would be coordinated with those at the plant and the mine, to maximize use and uniformity of equipment.

#### CONSTRUCTION PROCEDURES

Roadbed construction operations would disturb an average 200-foot wide corridor along most of the right-of-way; total mainline, siding, and access road construction disturbance would be approximately 1,000 acres.

Initial right-of-way preparation would consist of access and work road construction, installation of work roads to the top of cut areas, clearing of structures, disposal of debris, removal of vegetation, and stripping and stockpiling of topsoil. Water for fill compaction, dust control, and consumption would be obtained from existing sources if possible. New wells would be drilled and storage tanks installed if



necessary; the wells would be left in place, if so desired, for the use of private landowners or surface management agency.

Upon completion of the initial clearing, work would commence on the placement of drainage culverts and construction of bridges. Cattle crossings would be incorporated into drainage culverts at appropriate intervals. Where pipelines carrying flammable gas or oil are to be crossed by the railroad, the carrier pipe would be cased, sealed, and vented in accordance with the AREA (American Railway Engineering Association) Manual of Recommended Practice.

Excavation and embankment construction would involve the movement of earth materials as necessary to shape the railroad bed and obtain final grade elevation. Existing topography would be altered to meet alignment and the proposed railroad design criteria of 1 percent maximum grade and 6 degree maximum angle from horizontal. Embankment sides would be constructed at a maximum slope of one vertical to two horizontal (approximately 26 degrees from horizontal). This is expected to permit revegetation, although soil conditions, drifting snow, or other problems may dictate a more gentle slope.

All suitable excavated materials would be stored and used as fill to form the embankments for the roadbed. Fill operations would place excavated materials from cuts or nearby borrow pits in layers 8 to 10 inches thick, compacting it as it is placed; a water truck would wet the fill materials for maximum compaction. A 90 to 95 percent compaction density is desired on the roadbed fill; compaction would be monitored by performing standard compaction tests on collected samples.

If insufficient material is available from excavation areas, it would be necessary to obtain special use permits from the appropriate surface management agency to mine available areas adjacent to the rail



line. Operations in borrow pit areas would comply with regulations of the Wyoming Mine Land Act, with BLM and Forest Service stipulations, and with contract requirements. Borrow pits would be shaped to conform to the natural surroundings, revegetated, and provided with drainage facilities.

Upon completion of grading and shaping, the roadway would be surfaced with subballast material excavated, with surface management agency permission, from scoria deposits along the route; trucked to a rock crusher and screening plant; and hauled to the completed railroad bed. Although the primary use of scoria would be as subballast, ancillary facilities such as access roads, grade crossings, underpasses, and staging areas would require gravel for surfacing. The total project demand for scoria and gravel for all uses associated with railroad construction would be approximately 160,000 cubic yards.

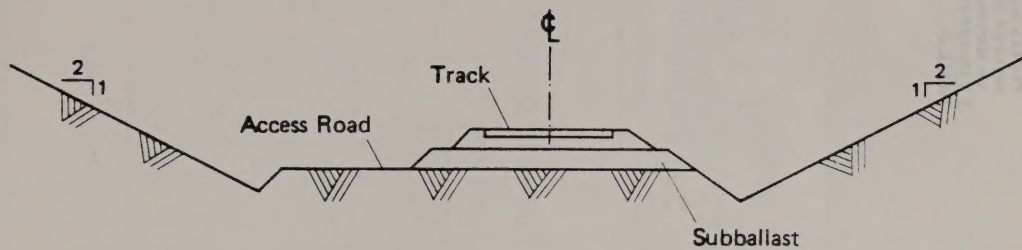
Following subballast placement, the track, welded into 2,000-foot sections at the plant site and transported to the construction area, would be laid and final welds made, and the final or primary ballast, consisting of crushed rock from local sources, would be installed and tamped.

Typical cut and fill sections are shown in Figure 3.5-4. Typical road crossing configurations and culvert designs are illustrated in Figures 3.5-5 and 3.5-6, respectively. Major equipment requirements for railroad construction are listed in Table 3.5-2.

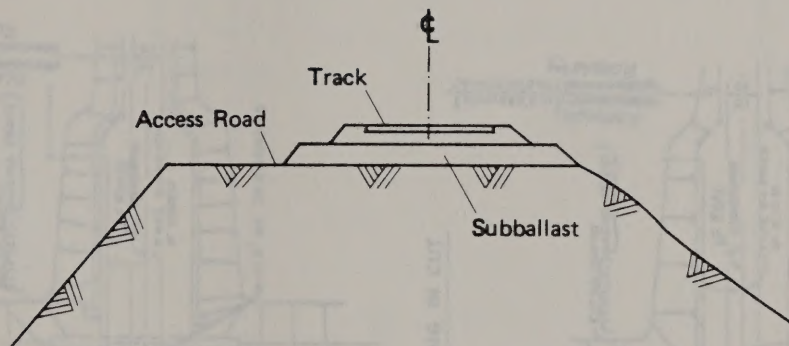
#### RAILROAD OPERATIONS

Coal handling would become the responsibility of WyCoalGas, Inc., as soon as the coal was loaded into railcars at the mine. Four identical unit trains, each with two electric locomotive units and





Cut Section



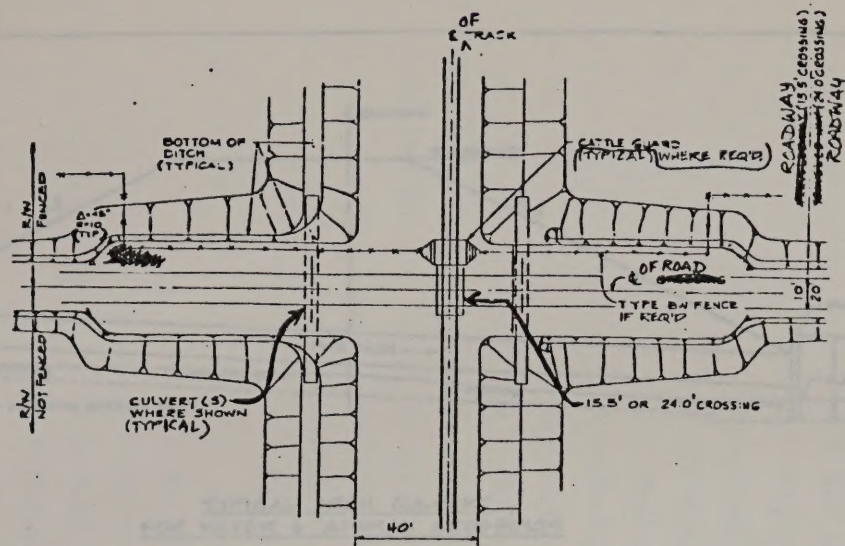
Fill Section

Figure 3.5-4  
TYPICAL CUT AND FILL SECTIONS

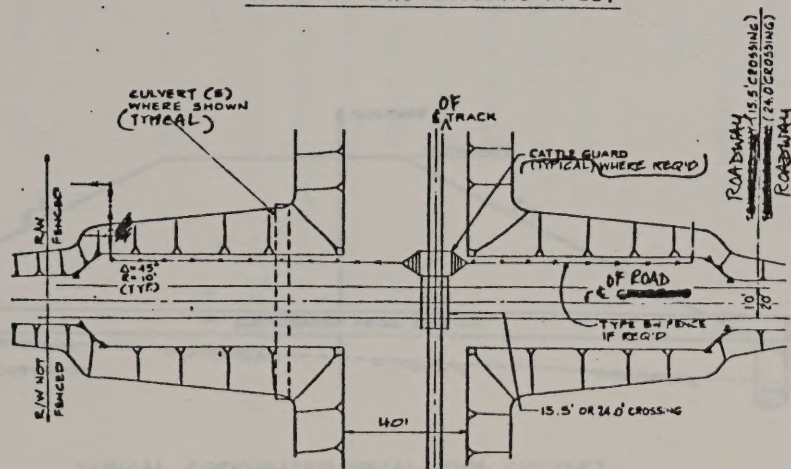
Figure 3.5-5. Typical Road Crossings  
by Proposed Electric Railroad



3-151



15.5' OR 24.0' CROSSING IN CUT

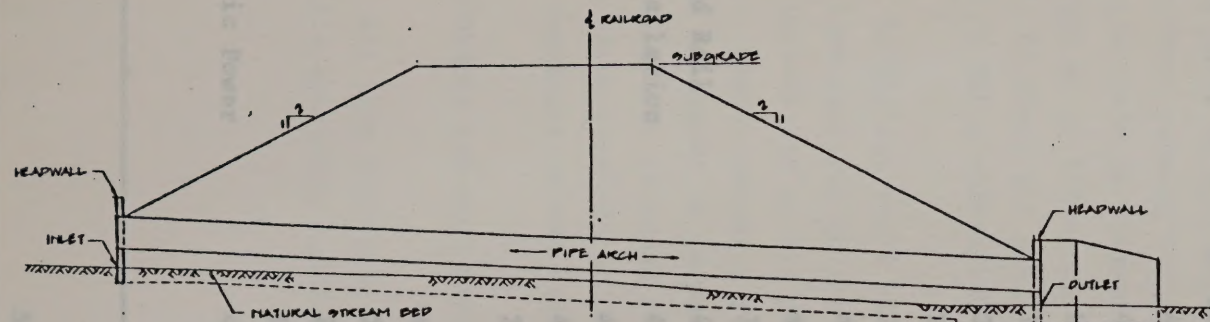


15.5' OR 24.0' CROSSING ON FILL

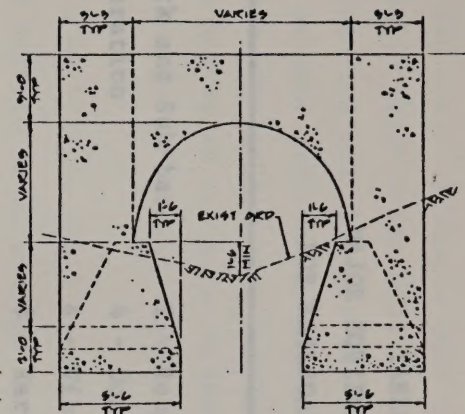
NOTES  
1. CROSSING PROTECTION <sup>Would</sup> BE AS RECOMMENDED BY THE AREA MAINT'L OF RECOMMENDED PRACTICE, UNLESS OTHERWISE REQUIRED.

Figure 3.5-5. Typical Road Crossings by Proposed Electric Railroad

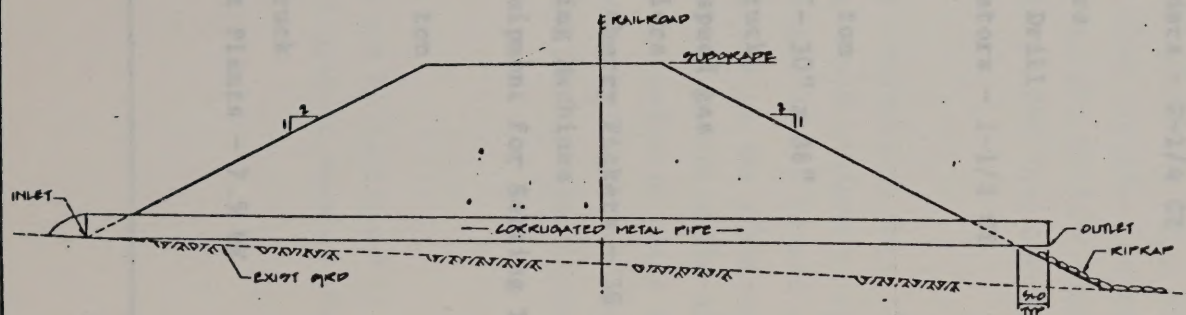




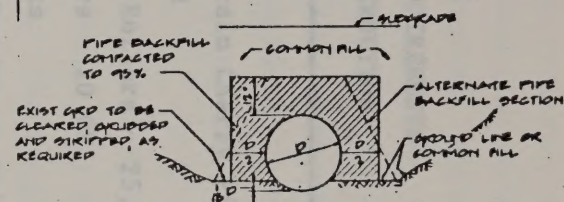
TYPICAL ARCH CULVERT  
FOR WATER & ANIMAL CROSSINGS



END VIEW TYPICAL HEADWALL



TYPICAL CORRUGATED METAL PIPE CULVERT



TYPICAL PIPE INSTALLATION  
IN COMMON FILL

Figure 3.5-6.  
Typical Culvert  
Details, Electric  
Railroad

3-152



TABLE 3.5-2

MAJOR EQUIPMENT REQUIREMENTS  
FOR RAILROAD CONSTRUCTION

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Sitework and Sub-base Preparation	2 - Rough Terrain Cherry Pickers - 30 tons
	4 - Dozers D9H
	4 - Vibratory Rollers - 25,000 lb
	8 - Earthmovers - 20 CY
	20 - Dump Trucks
	4 - Front-end Loaders - 2-1/4 CY
	4 - Motor Graders
	2 - Air Compressors
	1 - Wagon Mounted Drill
	2 - Crawler Excavators - 1-1/2 CY
	2 - Water Trucks
	2 - Fuel Trucks
	4 - Pickups - 3/4 ton
	6 - Plate Tampers - 30" x 36"
	1 - Maintenance Truck
Tie and Rail Installation	4 - Tractors - 4-speed gas
	4 - Platform Trailers
	4 - Rough Terrain Cherry Pickers - 30 ton
	4 - Portable Welding Machines
	2 - Special RR Equipment for Setting Ties and Rails
	4 - Pickups - 3/4 ton
	5 - Buses
	2 - Fuel Trucks
	1 - Maintenance Truck
Electric Power	4 - Portable Light Plants - 7.5 kW

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thirty-one 100-ton capacity bottom-dump railcars, would be used to haul the coal. A single unit train would therefore carry 3,100 tons of coal. Train units would be kept together, and used solely for transporting coal between the mine and the plant. During periods when ambient temperature was above freezing, thus allowing the wet process ash to be easily handled, the ash would be returned by train to be buried at the mine during the reclamation process; ash would be transported in separate rail cars designated for this purpose.

A unit train would be approximately 1,900 feet long. Trains would operate at an average speed of 35 miles per hour, passing a given point in approximately 40 seconds. The proposed rail line would have three passing sidings at roughly equal intervals along the route. A train would be dispatched every 2 hours from the mine. Four trains working on an 8-hour cycle (i.e., three trips per day), 6 days per week, 50 weeks per year would transport 11,160,000 tons per year of coal to the gasification plant.

Herbicides would be sprayed to control vegetation on a 12-foot corridor centered on the roadbed; spraying would conform to applicable regulations and to all provisions of the right-of-way permit or easement. Where necessary to prevent fires, grass in the right-of-way would be mowed; it is not anticipated that the entire right-of-way would have to be mowed for weed control. The railroad would be fenced only where required by regulation or at private landowners' request; the remainder of the railroad line would be left as open range.

#### ABANDONMENT AND RECLAMATION

All land disturbed by the railroad would be reclaimed to a productive condition consistent with past and present uses of the area.



Reclamation would begin upon project termination. On private lands, reclamation procedures would be at the landowner's discretion.

Pre-construction topsoil stockpiling methods would be as described for the gasification plant. Following project completion, the railroad tracks and ties would be salvaged and the subballast and ballast transported to the mine for burial. The railroad right-of-way would be graded to blend with the surrounding topography (except for the deeper cuts and fills). Topsoil replacement, mulching, seeding, and maintenance would also be as described for the gasification plant.

From flood flow in the North Platte River. Ground water would augment these surface sources when necessary; proposed ground-water sites are the South Well Field, west of Douglas, and the North Well Field, west of the plant site. The water well fields are shown in Figures 3.6-1 and -2. Water from these sources would be pumped directly to the plant as needed.

A private storage reservoir, Combs Reservoir, would be constructed to store surface water. Water to which MyCoalGas has rights (see below) would flow from LaPrairie Reservoir down LaPrairie Creek into the North Platte River and be pumped from a diversion facility on the river to the storage reservoir; thus no pipeline would be required for this source. When available, flood water from MyCoalGas' 1978 appropriation of the North Platte River (see below) would be diverted to the reservoir at the same diversion facility. Collection and transmission pipelines and several pumping stations would complete the system, as shown in Figures 3.6-1 and 3.6-2.

The choice of water sources would be as follows. North Platte River flood flow would be used first, when available. LaPrairie Reservoir water would be used second, as available, to the allowed maximum



### 3.6 WATER SUPPLY SYSTEM

#### GENERAL DESCRIPTION

At full production, the proposed coal gasification plant would require, annually, approximately 7,900 acre-feet of water for SPG production, plus an estimated 2,000 acre-feet to offset evaporation and conveyance losses. Of this total, 1,720 acre-feet would come from moisture in the coal itself, and the remaining 8,180 acre-feet would be furnished from a three-part supply system. Surface water would be obtained from the existing LaPrele Reservoir southwest of Douglas, and from flood flow in the North Platte River. Ground water would augment these surface sources when necessary; proposed ground-water sites are the South Well Field, west of Douglas, and the North Well Field, west of the plant site. The water well fields are shown in Figures 3.6-1 and -2. Water from these sources would be pumped directly to the plant as needed.

A private storage reservoir, Combs Reservoir, would be constructed to store surface water. Water to which WyCoalGas has rights (see below) would flow from LaPrele Reservoir down LaPrele Creek into the North Platte River and be pumped from a diversion facility on the river to the storage reservoir; thus no pipeline would be required for this source. When available, flood water from WyCoalGas' 1974 appropriation of the North Platte River (see below) would be diverted to the reservoir at the same diversion facility. Collection and transmission pipelines and several pumping stations would complete the system, as shown in Figures 3.6-1 and 3.6-2.

The choice of water sources would be as follows. North Platte River flood flow would be used first, when available. LaPrele Reservoir water would be used second, as available, to the allowed maximum



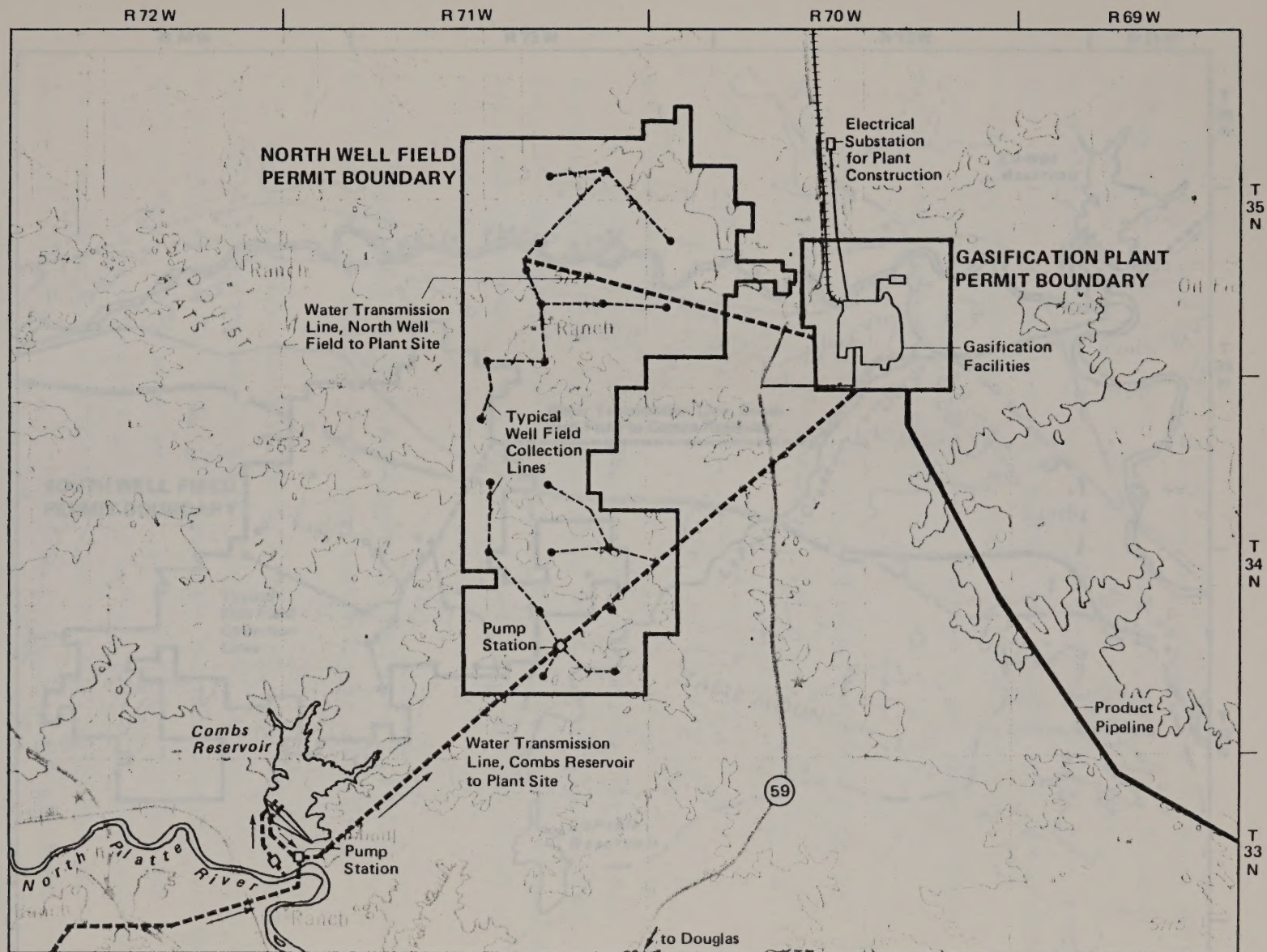


Figure 3.6-1  
NORTH WELL FIELD AND COMBS RESERVOIR LOCATION



3-158

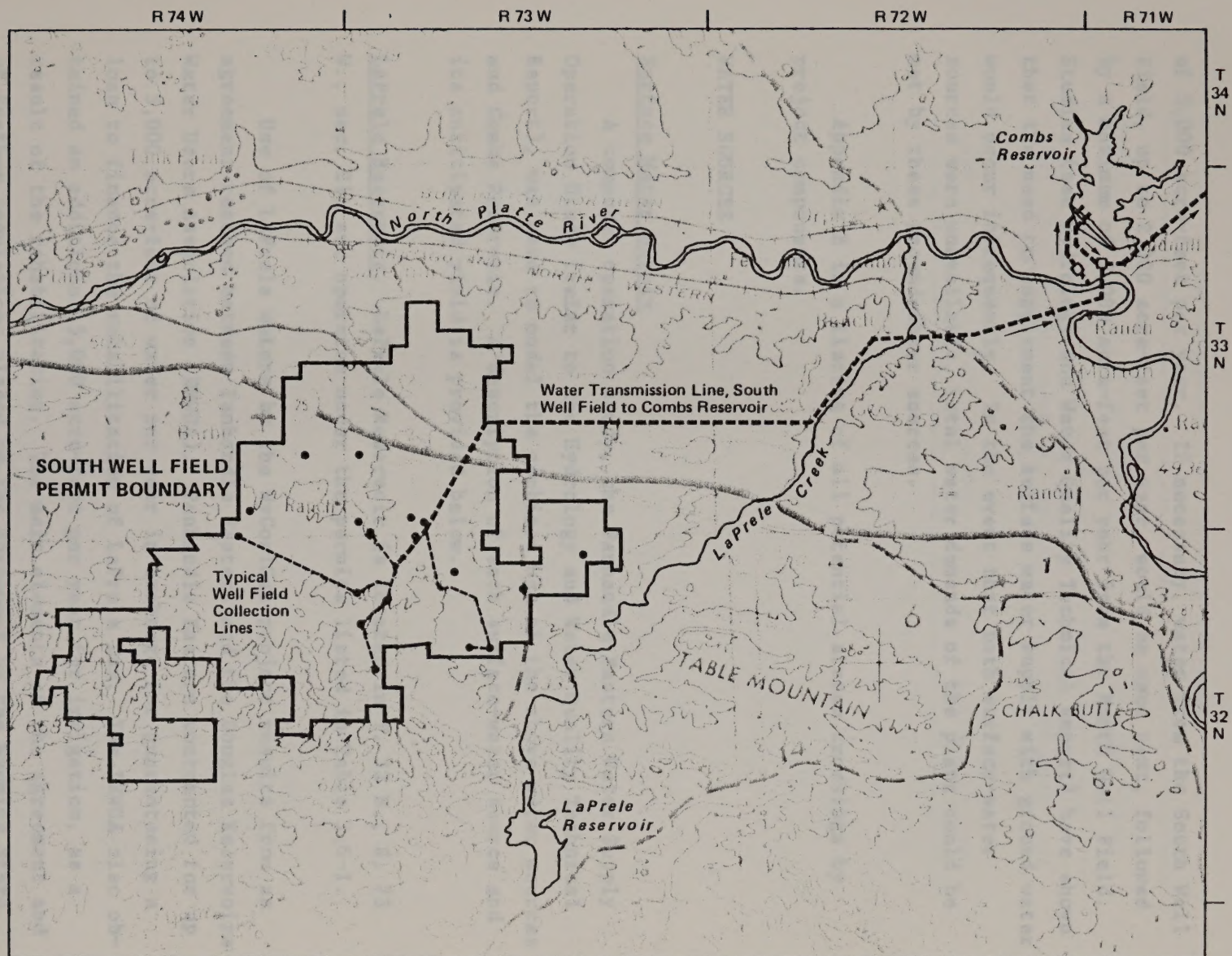


Figure 3.6-2  
SOUTH WELL FIELD, LAPRELE RESERVOIR, AND COMBS RESERVOIR LOCATION



of 5,000 acre-feet per year. If necessary, water from the South Well Field, up to 2,000 acre-feet per year, would be used next, followed by a maximum of 2,000 acre-feet per year from the North Well Field. Studies (see Hydrology and Water Quality Technical Report) have shown that the need to supplement the surface water supply with ground water would occur infrequently. In the event that both surface-water sources were unavailable, total water demands of the plant could be met by these ground-water sources.

Appendix B is a listing of all potential stream crossings by project components.

#### WATER SOURCES

##### Surface Water Supply

A computer operation study, the Panhandle Eastern Water Supply Operation Study (refer to the Hydrology and Water Quality Technical Report), was used to model the combined use of the above water sources and Combs Reservoir. A description of each surface-water source and its anticipated yield is provided below.

LaPrele Reservoir. LaPrele Reservoir is located in T. 32 N., R. 73 W., sec. 21, and operates under the permits listed in Table 3.6-1.

Use of LaPrele waters by the WyCoalGas project results from an agreement reached between Panhandle Eastern and the Douglas Reservoirs Water Users Association (DRWUA). Panhandle Eastern contracted for up to 5,000 acre-feet of water per year in exchange for guaranteeing a loan to finance the rehabilitation of LaPrele Dam. The DRWUA also obtained an additional 5,000 acre-feet per year for irrigation, as a result of the rehabilitation. The main elements of the agreement and of further regulations placed on the agreement by the Wyoming State Board of Control Order No. 20 are as follows:



TABLE 3.6-1

## OPERATING PERMITS, LAPRELE RESERVOIR

Permit	Priority	Storage Right
728R	September 21, 1905	15,106 acre-feet
1581R	July 7, 1909	4,894 acre-feet

4. During the irrigation season, if insufficient water is expended to supply both the irrigated lands and Panhandle's contract, the available water shall be apportioned 75 percent to irrigation needs and 25 percent to WyCoalGas.
5. Any dam leakage shall be accepted for as storage water and charged and delivered to WyCoalGas as a portion of their 5,000 acre-foot entitlement.
6. The reservoir shall be operated under the one-fill criterion, with all releases to WyCoalGas deducted from the annual entitlement of water for LaPrele Reservoir.
7. Conveyance losses from LaPrele Dam to WyCoalGas's point of diversion shall be charged to WyCoalGas.

Based on the above criteria, a separate operation study of LaPrele Reservoir was conducted, modeling the period 1910-1919. The study showed that, on the average, a volume of 4,610 acre-feet of water per year would have been available below the LaPrele Dam for the WyCoalGas project. The lowest amount of water available for WyCoalGas in any one year would be 2,400 acre-feet. A conveyance loss of 10 percent was assumed from LaPrele Dam to the point of diversion, a distance of approximately 30 miles along LaPrele Creek and 4.3 miles along the North Platte River.

In almost every year of the LaPrele study, little or no water would be available to WyCoalGas in the months of August and September because of the large amount of land served by the relatively small



1. No water rights on LaPrele Creek shall be injured.
2. WyCoalGas can receive up to 2,500 acre-feet on a reasonably uniform basis during the nonirrigation season (October 1 to April 30).
3. During the irrigation season (May 1 to September 30), WyCoalGas can receive up to the difference between actual deliveries during the immediately preceding nonirrigation season and 5,000 acre-feet, delivered on a reasonably uniform basis.
4. During the irrigation season, if insufficient water is impounded to supply both the irrigation needs and Panhandle's contract, the available water shall be apportioned 75 percent to irrigation needs and 25 percent to WyCoalGas.
5. Any dam leakage shall be accounted for as storage water and charged and delivered to WyCoalGas as a portion of their 5,000 acre-foot entitlement.
6. The reservoir shall be operated under the one-fill criterion, with all releases to WyCoalGas deducted from the annual entitlement of water for LaPrele Reservoir.
7. Conveyance losses from LaPrele Dam to WyCoalGas's point of diversion shall be charged to WyCoalGas.

Based on the above criteria, a separate operation study of LaPrele Reservoir was conducted, modeling the period 1930-1979. The study showed that, on the average, a volume of 4,610 acre-feet of water per year would have been available below the LaPrele Dam for the WyCoalGas project. The lowest amount of water available for WyCoalGas in any one year would be 2,400 acre-feet. A conveyance loss of 10 percent was assumed from LaPrele Dam to the point of diversion, a distance of approximately 20 miles along LaPrele Creek and 4.3 miles along the North Platte River.

In almost every year of the LaPrele study, little or no water would be available to WyCoalGas in the months of August and September. Because of the large amount of land served by the relatively small



LaPrele Reservoir, shortages to the irrigators and WyCoalGas occurred as early as June several times in the operation study; shortages to the irrigators would occur almost every year in the late irrigation season even without the involvement of WyCoalGas. Historically, such shortages have been the case. In the model, the most consistent yield to the WyCoalGas project occurs during the nonirrigation season, when the average effective yield would be the full nonirrigation season apportionment of 2,500 acre-feet.

Direct Flow Right from the North Platte River. Panhandle Eastern obtained a direct flood flow right from the North Platte River with a priority date of 1974, and a storage right for the North Platte water in Combs Reservoir. The extraction point on the North Platte would be in T. 33 N., R. 71 W., sec. 7. The proposed project would be able to obtain water from the North Platte, when in priority, at a maximum rate of 201.2 cfs, not to exceed 26,539 acre-feet for storage in any year.

The availability of North Platte River water in the Panhandle Eastern Water Supply study was based on results of a North Platte River operational study developed by the Water Resources Research Institute (WRRI). This model simulates the North Platte River system, accounting for all gains, storage rights, and power operation needs for the large government reservoirs, irrigation requirements, river losses, and interstate compacts with Nebraska. The model was first developed in June of 1977, and has since been revised and updated. Agencies participating in and reviewing the revised model are the Wyoming State Engineer's Office and the U.S. Bureau of Reclamation.

From the WRRI study, the gain in the North Platte River system above all demands and interstate agreements (referred to as "Owed To the River" water) would be available under Panhandle Eastern's 1974



priority. For the Panhandle Eastern Water Supply study it was assumed that there must be more than 6,000 acre-feet of "Owed To the River" (O.T.R.) water available in any month before any water becomes available to WyCoalGas. This would provide an administrative water "cushion" to assure that no adverse effects would result to prior rights on the North Platte River. All O.T.R. water in excess of 6,000 acre-feet per month, but limited to WyCoalGas' right of 201.2 cfs (approximately 12,000 acre-feet per month) was made available to WyCoalGas in the study. In many cases, water that was available to WyCoalGas was bypassed because of a lack of storage space in Combs Reservoir. The 50-year average of O.T.R. water for the period 1930-1979, obtained from the WRRRI study, was 124,300 acre-feet per year. The Panhandle Eastern Water Supply study projected that, during the study period 1930-1979, the average availability of O.T.R. water to the WyCoalGas project would have been 11,500 acre-feet per year, and that WyCoalGas would have been able to divert, on the average, only 3,600 acre-feet per year, or less than 3 percent of the total O.T.R. water in the North Platte River.

North Platte River water would not be available to WyCoalGas every year and is typically available only in the months of April through June. During the relatively dry period of 1954-1967, WyCoalGas would have had North Platte water available to them only during three months and in quantities insufficient to completely fill Combs Reservoir. The volume of O.T.R. water is usually large when it does occur; for example, as much as 758,400 acre-feet has been available in a single month.

Combs Reservoir lies on Soldier Creek drainage and would be entitled to flows from Soldier Creek. No records of flows for this creek are available, however. Similar drainages show a great variation in the amount of flow available from year to year, ranging from



2 to over 2,000 acre-feet. It was felt that flows from Soldier Creek would not be a reliable source of water. Therefore, to remain conservative relative to the overall water supply, Soldier Creek flows were not included as a water source.

#### Ground-Water Supply

Applications for nine wells in the South Well Field and 19 wells in the North Well Field area were submitted to the Wyoming State Engineer on February 12, 1974, and are currently being held in a pending status. According to current operation studies being conducted for Combs Reservoir, ground water would be required to make up surface water deficits for 5 years of a total 50-year simulation period. The ground-water requirements during these years (1930-1979) range from 1,050 to 2,680 acre-feet per year.

North Well Field. The North Well Field is anticipated to consist of 20 wells with capacities of 100 to 300 gallons per minute (gpm) each; see Figure 3.6-1.

South Well Field. The South Well Field is expected to consist of approximately 10 to 12 wells with capacities of 300 to 600 gpm each. Some of the wells would be used for standby purposes. The location of the wells is shown in Figure 3.6-2.

#### OTHER SYSTEM COMPONENTS

##### Combs Reservoir and Dam

Combs Reservoir would be located on Soldier Creek northwest of Douglas and would have a normal maximum storage capacity of 26,539 acre-feet. The major function of this reservoir would be the storage of water from Panhandle Eastern's 1974 North Platte right. The reser-



TABLE 3.6-2

voir would also serve to store water belonging to WyCoalGas but in excess of plant needs at the time it is available. Water would be appropriated for and diverted to the reservoir under the Wyoming filings shown in Table 3.6-2.

The proposed dam, reservoir, and access road are shown in Figure 3.6-3. Figure 3.6-4 is an artist's conception of the reservoir. Following are descriptions of the dam, emergency spillway, and the reservoir itself.

Dam. The dam would be a zoned earth embankment approximately 114 feet above the original ground surface at Soldier Creek. It would have a crest elevation of 4,976 feet and a crest length of approximately 6,500 feet. The upstream slope of the embankment would have a 3:1 slope and the downstream slope would be 2-1/2:1. The dam would have a compacted earth cutoff excavated 10 feet into the underlying bedrock. Four zones of earthwork are planned in the embankment. Upstream slope protection would be provided by 30 inches of riprap on 12 inches of bedding. Downstream slope protection would be provided by seeded topsoil.

Emergency Spillway. The spillway, located on the right abutment, would consist of approach channel, crest structure, chute, and terminal structure. The spillway is designed to handle the Maximum Probable Flood (MPF). Maximum discharge routed through the spillway would be 7,670 cfs at a maximum reservoir elevation of 4,973.34 feet.

The approach channel to the spillway would be unlined, with the exception of the approximately 150 feet from the spillway crest to the centerline of the dam, which would be lined with gabions. The crest itself would be a concrete structure anchored to bedrock. The



TABLE 3.6-2

## COMBS RESERVOIR STORAGE RIGHT FILINGS

Water Right Filing Number	Date	Storage Right or Flow Rate
7613 Res	February 14, 1974	24,190 acre-feet
7614 Res	July 9, 1974	2,349 acre-feet
24403	February 14, 1974	
6523 Enl	March 28, 1974	
6524 Enl	July 9, 1974	201.2 cfs

Figure 3.6-3  
COMBS RESERVOIR AND NORTH PLATTE DIVERSION FACILITY



3-167

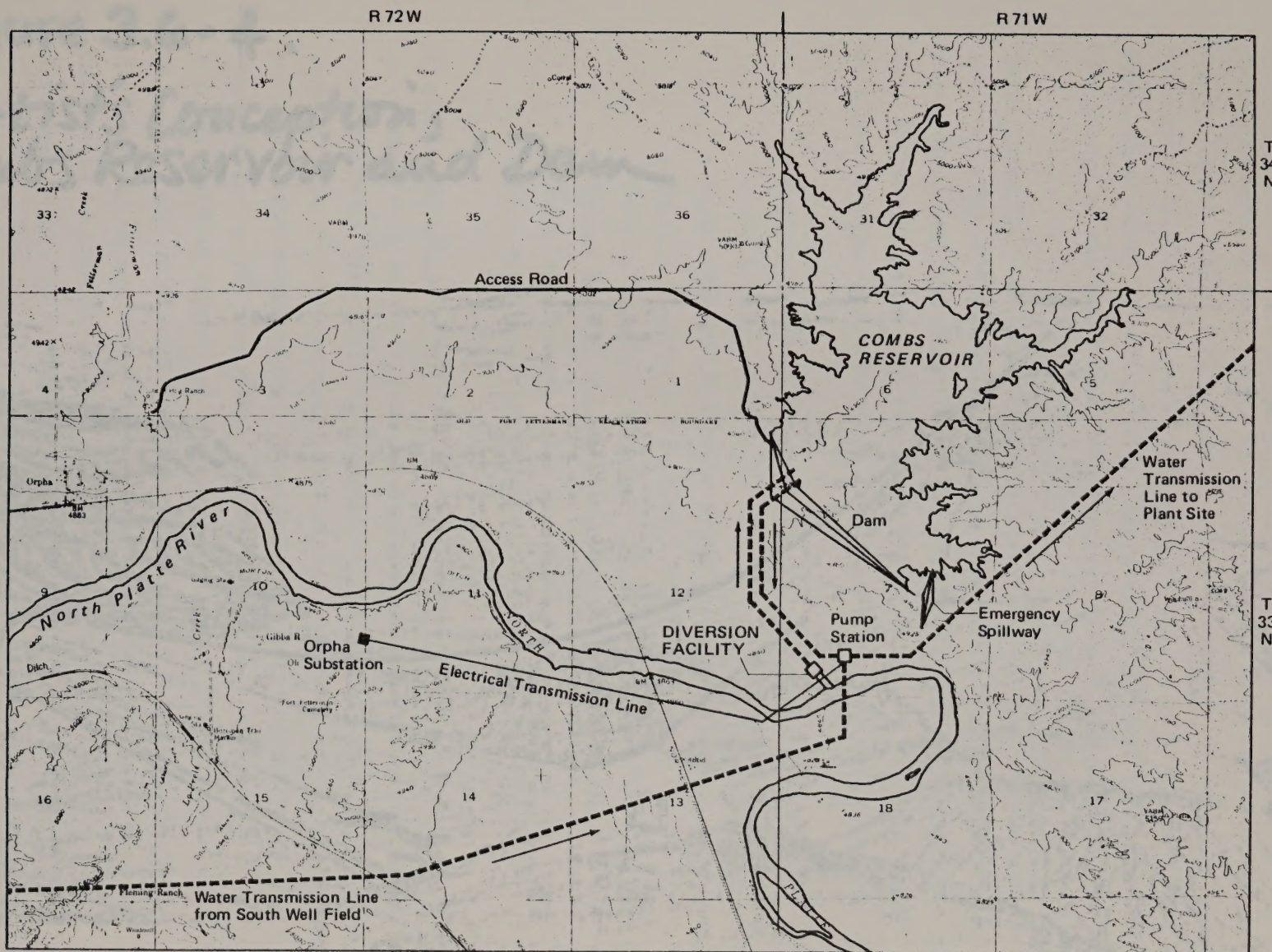


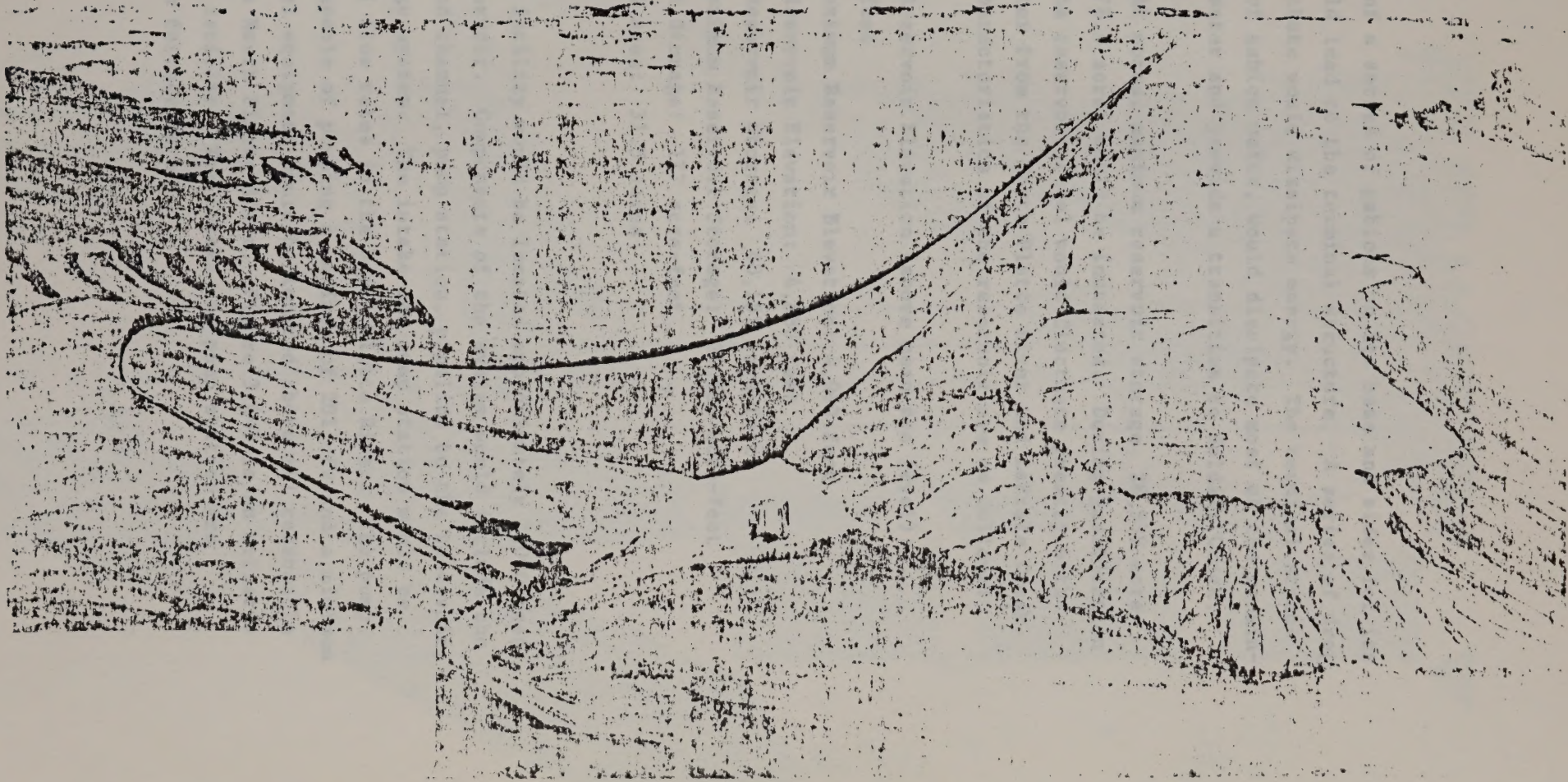
Figure 3.6-3  
COMBS RESERVOIR AND NORTH PLATTE DIVERSION FACILITY



Figure 3.6-4.

Artist's Conception,  
Combs Reservoir and Dam

3-168





chute, consisting of a series of gabions on its base and sides for its entire length, would lead to the terminal structure. A series of drop structures in the chute would dissipate energy. The terminal structure, constructed of gabion units, would dissipate most of the remaining energy of the water and provide a transition to Soldier Creek.

Combs Reservoir. At normal maximum reservoir storage, 26,539 acre-feet, an area of 878.4 acres would be inundated. During gasification plant operations the reservoir level would fluctuate greatly with availability of water from the North Platte River and LaPrele Creek. Pertinent design characteristics of the reservoir are as follows:

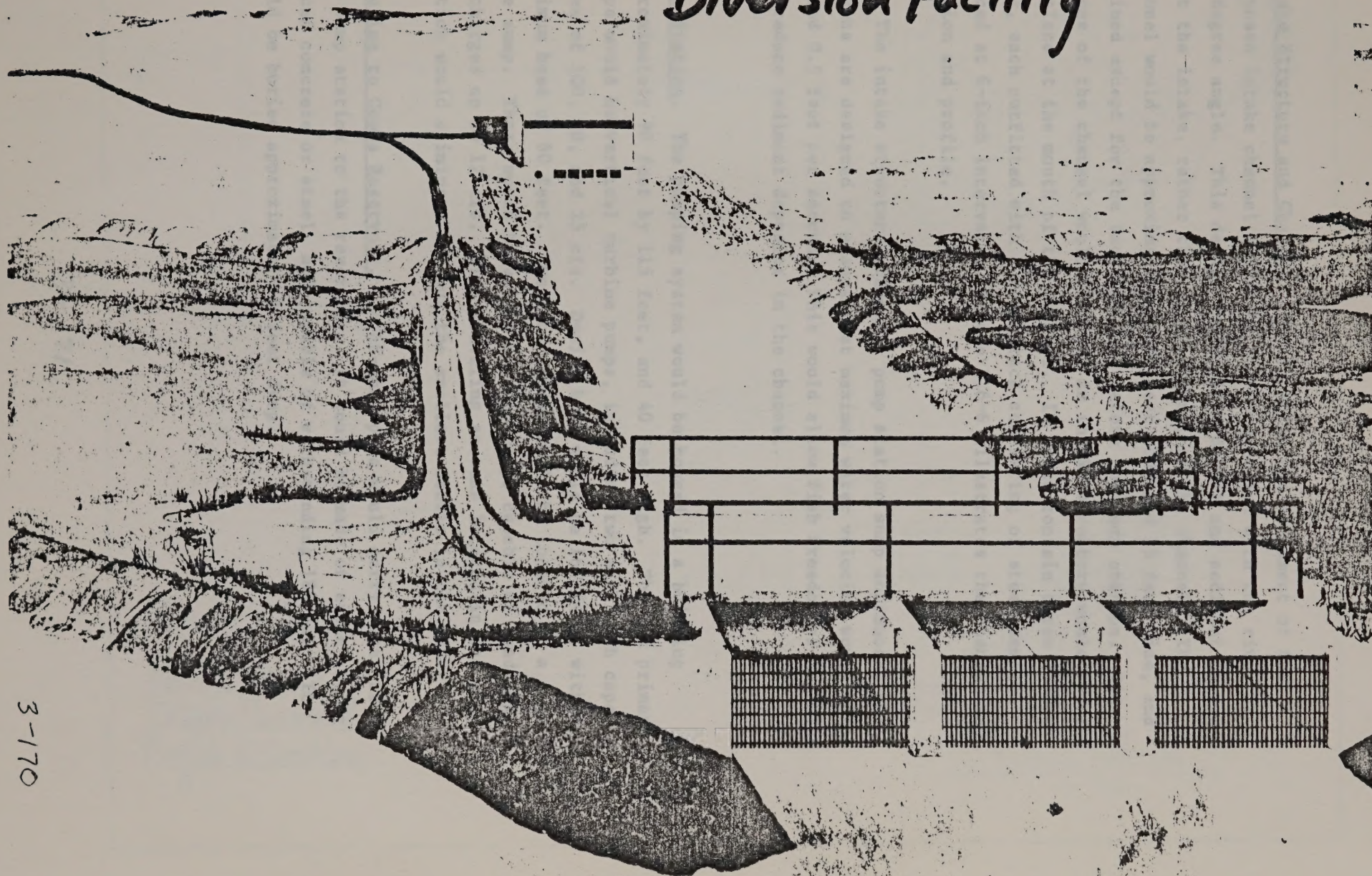
- Maximum Reservoir Elevation (above mean sea level):  
4,973.4 feet
- Normal Maximum Reservoir Elevation: 4,960 feet
- Minimum Reservoir Elevation: 4,880 feet
- Maximum Reservoir Storage: 40,155 acre-feet
- Normal Maximum Reservoir Storage: 26,539 acre-feet
- Dead Pool Storage: 177 acre-feet
- Dead Pool Area: 31.5 acres

#### Diversion Facility

The diversion facility would be located approximately 3,000 feet south of Combs Reservoir. Components of the system would include the intake structure and channel, pump station, pipeline to the reservoir, and associated surge system. The intake and pump station would be operable during all flow rates in the North Platte River. The pump station would be capable of pumping a maximum of 201 cfs and a minimum of 9 cfs. All vital equipment would be located above all reasonable flood levels of the North Platte River. Figure 3.6-5 is an artist's conception of this facility. The intake and pump station are described below, in further detail.



Figure 3.6-5  
North Platte River  
Diversion Facility





Intake Structure and Channel. The location and alignment of the proposed intake channel calls for an intersection with the river at a 45 degree angle. This design would allow debris and sediment to sweep past the intake, rather than being drawn into the channel. The channel would be approximately 1,000 feet long and 75 feet wide, and unlined except for the last 200 feet before the pump station. Side slopes of the channel would be 3:1. An intake structure would be cast in place at the mouth of the channel. It would contain three 20-foot bays, each outfitted with a trash rack consisting of steel members spaced at 6-inch intervals. Figure 3.6-6 illustrates the channel in section and profile.

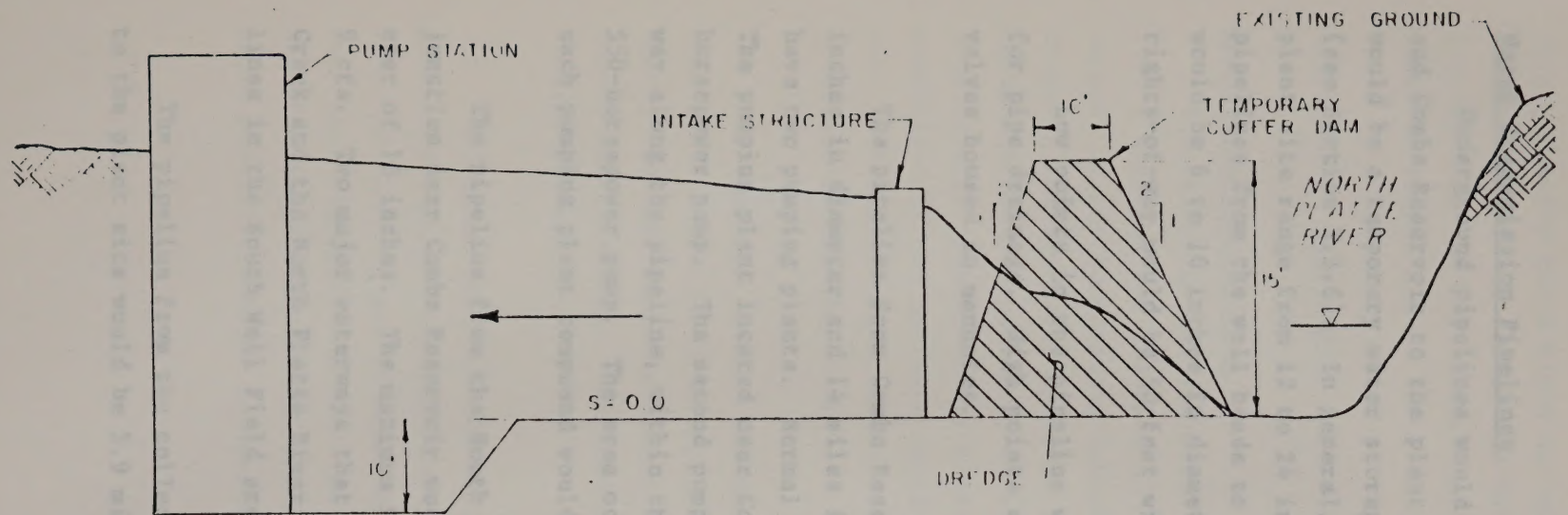
The intake structure, channel, pump station sump entrances, and screens are designed to ensure that maximum water velocity would not exceed 0.5 feet per second. This would allow fish freedom of movement and reduce sediment deposits in the channel.

Pump Station. The pumping system would be housed in a building approximately 90 feet by 115 feet, and 40 feet high. The six primary pumps would be vertical turbine pumps, including two each with capacities of 100, 50, and 25 cfs. Design head would be 160 feet, with a minimum head of 60 feet. Two other pumps would be located in a separate sump. These would be variable-speed pumps capable of handling discharges up to 12 cfs. Five traveling screens located in the pump station would eliminate all but the smallest debris in the water.

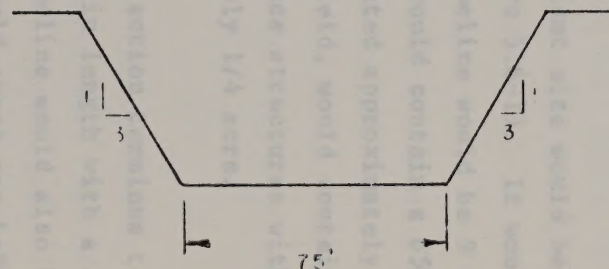
Pipeline to Combs Reservoir. A 66-inch pipe would carry water from the pump station to the reservoir. It would be made of either reinforced concrete or steel, and capable of withstanding 185 psi. It would be buried approximately 5 feet deep.



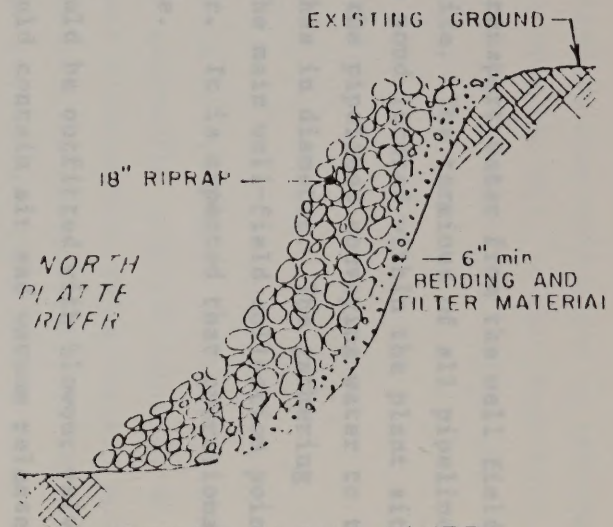
3-172



PROFILE  
NO SCALE



INTAKE CHANNEL  
TYPICAL SECTION  
NO SCALE



RIPRAP ALONG RIVER  
TYPICAL SECTION  
NO SCALE

Figure 3.6-6.  
North Platte  
Intake Channel,  
Profile & Section



### Water Transmission Pipelines

Underground pipelines would transport water from the well fields and Combs Reservoir to the plant site. The terminus of all pipelines would be a temporary water storage pond located within the plant site (see Section 3.3.6). In general, the pipelines conveying water to the plant site range from 12 to 24 inches in diameter. The gathering pipelines from the well heads to the main well-field collection points would be 6 to 10 inches in diameter. It is expected that operational rights-of-way would be 50 feet wide.

Low points in the pipeline would be outfitted with blowout valves for pipe drainage. High points would contain air and vacuum release valves housed in manholes.

The pipeline from Combs Reservoir to the plant site would be 24 inches in diameter and 14 miles in length (Figure 3.6-1). It would have two pumping plants. Normal flow in the pipeline would be 9 cfs. The pumping plant located near Combs Reservoir would contain a 650-horsepower pump. The second pumping plant, located approximately mid-way along the pipeline, within the North Well Field, would contain a 550-horsepower pump. The area occupied by surface structures within each pumping plant compound would be approximately 1/4 acre.

The pipeline from the South Well Field collection terminus to the junction near Combs Reservoir would be 14 miles in length with a diameter of 18 inches. The maximum flow in this pipeline would also be 9 cfs. Two major waterways that the pipeline would cross are LaPrele Creek and the North Platte River. Locations of the collection pipelines in the South Well Field are shown in Figure 3.6-2.

The pipeline from the collection terminus at the North Well Field to the plant site would be 5.9 miles in length and 14 inches in diam-



TABLE 3.6-3

eter. Booster pumps might be required at some well sites to provide sufficient head to convey the water from the well to the plant site. Locations of the collection pipelines in the North Well Field are shown in Figure 3.6-1.

## CONSTRUCTION PROCEDURES

### Combs Reservoir and Dam

The reservoir and dam areas would be cleared of all trees. Following clearing and grubbing of the excavation area and grouting of a segment of the foundation, embankment construction would begin. Portions of the reservoir would be excavated to provide material for the embankment; these materials would be transported from borrow areas in dump trucks. Fugitive dust generated during construction would be controlled by the periodic application of water to haul roads, borrow pits, embankment construction areas, and any other areas with the potential to generate dust.

The upstream face of the dam would be protected by riprap placed from the crest down to an appropriate level below the low-water level. Riprap material would be hauled from sites west of Douglas or from a quarry near Guernsey. The downstream slope would be vegetated for erosion protection.

Overburden soils in the vicinity of the spillways should be excavated with conventional heavy earth-moving equipment. On the basis of drilling and seismic velocity information, excavation of the very hard claystone and sandstone bedrock would probably require the use of a large tractor equipped with a single-tooth hydraulic ripper. Table 3.6-3 lists major equipment required for reservoir construction.



TABLE 3.6-3

## EQUIPMENT REQUIRED FOR RESERVOIR CONSTRUCTION

Item	Number
Concrete Batch Plant	1
Aggregate Screening Plant	1
Cranes	4
Trucks	18
Light Plants	10
Scrapers	20
Push Cats	2
Dozers with Ripper	4
Compacters	3
Industrial Disc	2
Waterwagons	2
Patrols	3
Backhoe	1
Dragline	1
Loaders	4
Drilling Rig	2
Grout Pump	2
Concrete Pump	1



### Re-entry Channel and Pump Station

The construction of the intake channel would begin with the excavation of all but the last fifty feet of the channel adjacent to the river; the unexcavated portion would serve as a cofferdam during the construction of the intake structure and pump station. After these two structures have been completed, a cofferdam would be built in the river to permit completion of the intake channel. Riprap would be placed on the sides and bottom of the intake channel upstream of the gate structure and on the bank of the river for a distance of fifty feet on each side of the intake channel. The cofferdam would then be removed, and the bottom of the river channel would be dredged to allow low river flows to enter the intake channel.

### Well Fields

Typical layouts for the two well fields are shown in Figures 3.6-1 and 3.6-2. After construction of access roads, a drill pad would be installed on each well site, as shown in Figure 3.6-7.

During drilling operations, approximately 2.5 acres would be cleared and leveled at each well site in a manner that would minimize cut-and-fill and the alteration of natural drainage courses. On steep slopes the exposed surfaces would be stabilized with rock, riprap, and other materials as appropriate to reduce erosion and prevent sediment from entering natural drainage courses. A 40,000-barrel-capacity mud pit would be located on the drill pad.

Standard drilling procedures would be employed. A 17-inch-diameter hole would be drilled and cased to a depth of 100 feet. A 12-inch-diameter hole would then be drilled and cased to a depth of 1,800 feet. At this depth an 8.75-inch hole would be drilled and cased to the top of the formation. The hole casing would be cemented from the top of the formation to the surface to prevent cross contamination between any aquifers or hydrocarbon reservoirs encountered.



33-177

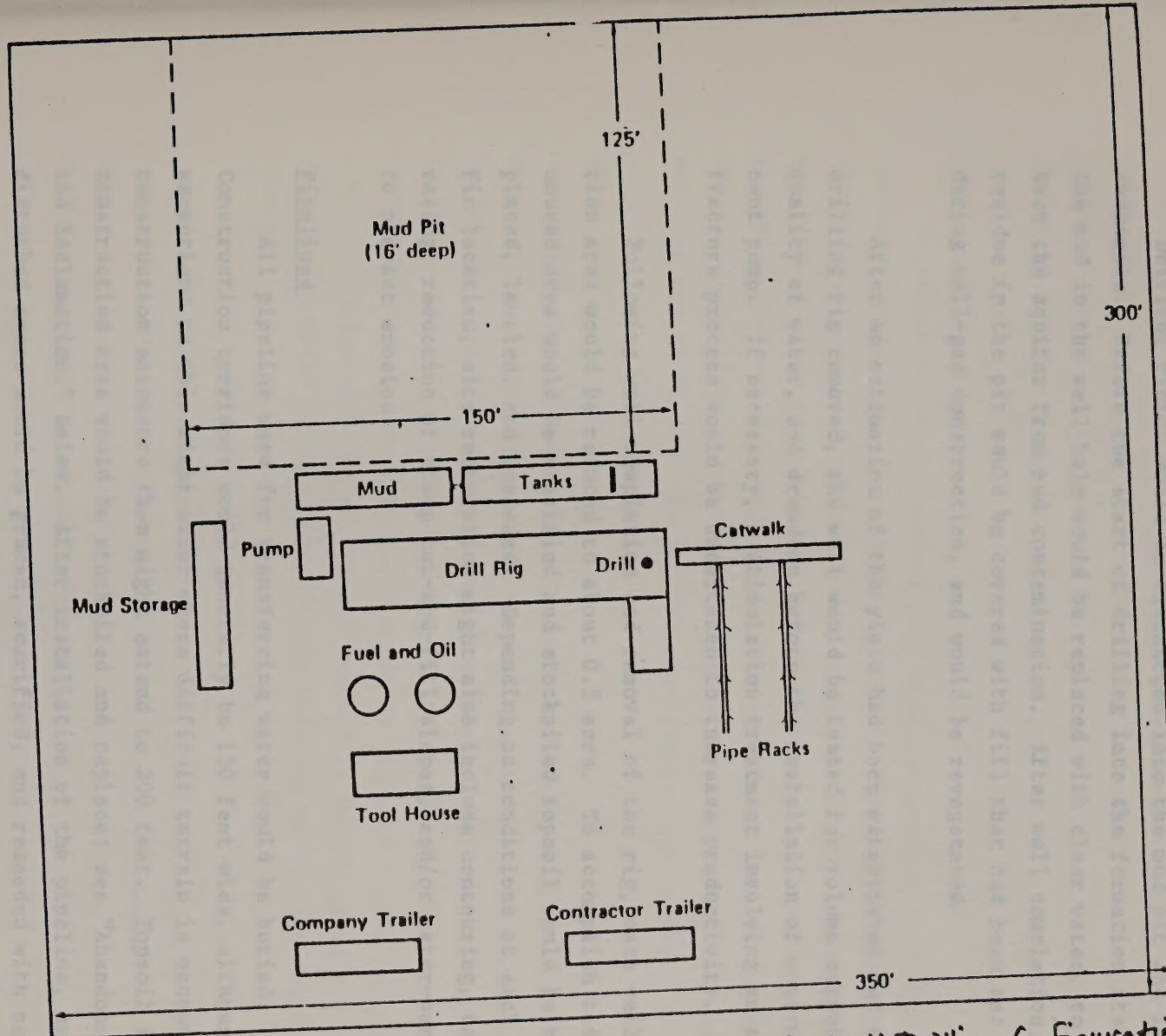


Figure 3.6-7. Water Well Drilling Configuration



Drilling fluids would be discharged into the mud pit and left to evaporate. Before the start of drilling into the formation itself, the mud in the well hole would be replaced with clear water, to protect the aquifer from mud contamination. After well completion, the residue in the pit would be covered with fill that had been set aside during well-pad construction, and would be revegetated.

After an estimation of the yield had been established and the drilling rig removed, the well would be tested for volume output, quality of water, and drawdown before the installation of a permanent pump. If necessary, a stimulation treatment involving an acid-fracture process would be undertaken to increase productivity.

Following well completion and removal of the rig, each well location area would be reduced to about 0.5 acre. To accomplish this, the unused area would be scarified and stockpiled topsoil would be replaced, leveled, and reseeded. Depending on conditions at each specific location, site restoration might also include contouring, terracing, reduction of steep cut-and-fill slopes, and/or water-barring to prevent erosion.

#### Pipelines

All pipeline used for transferring water would be buried. Construction corridors would generally be 150 feet wide, although exceptions to this might exist where difficult terrain is encountered; construction easements then might extend to 200 feet. Topsoil in the construction area would be stockpiled and replace; see "Abandonment and Reclamation," below. After installation of the pipeline, any disturbed areas would be graded, scarified, and reseeded with native species. No maintenance of the corridor is anticipated once the vegetation has reestablished itself. Pipeline construction procedures are essentially identical to those discussed in the following section for the product pipeline.



TABLE 3.6-4

## EQUIPMENT REQUIRED FOR PIPELINE CONSTRUCTION

Equipment required for water pipeline construction is listed in Table 3.6-4. Pipelines 12 inches or more in diameter would be completed at the rate of about one mile per day; pipelines less than 12 inches in diameter would be completed at 1-1/2 to 2 miles per day.

Pump Stations

As discussed above, several pump stations would be installed on the water transmission line to the plant site (Figure 3.6-1). Each station would be located on a 3-acre fenced site. Once completed, about one-quarter acre would be occupied by surface structures; the remaining area would be reclaimed and revegetated. All aboveground structures would be painted to blend with the surrounding landscape; refer to the section on the product pipeline for discussion.

Roads

Roads would be improved and constructed to provide all-weather access to the major features of the water supply system. Permanent access would be required to Combs Reservoir and its appurtenant structures, to the wells, to the pumping plants on the pipeline, and to the reentry channel. Temporary roads would be required during construction, following pipeline routes and leading to borrow areas and other sites. The roads would connect to the existing county and state road systems.

Approximately 28 miles of new or improved roads would be constructed in support of the water supply system construction, approximately 3 miles in the vicinity of the reservoir, 9 miles at the South Well Field, and 16 miles at the North Well Field.



TABLE 3.6-4

## EQUIPMENT REQUIRED FOR PIPELINE CONSTRUCTION

Item	Number
Backhoe	2
Loaders	2
Patrol	1
Dozer with Ripper	1
Trucks	8
Crane	1
Compaction Equipment	1
Pumps	4
Boring Equipment	1
Farm Tractor and Spreader	1

In general, subsoil would be replaced over the pipe to within eight inches of the surface of the trench, and lightly compacted with a rubber-tired motor grader. Topsoil would then be rolled in to form an eight-inch crown over the trench to compensate for normal settlement.

Following backfilling and the construction of waterbreaks, the topsoil would be mulched with clean straw and seeded with the mixture described for the vegetation plan. Seeding would take place in the fall after October 15. Seeding would be done with a drill where possible. In areas too steep for drill equipment, broadcast seeding at double the drill-seed rate would be used. Harrowing, brush dragging,



## ABANDONMENT AND RECLAMATION

Except for above-ground components of the system, all lands to be disturbed would be reclaimed to a productive condition consistent with the past and present uses of the area. Since the WyCoalGas water rights will be sold after project termination, it is expected that the water supply system would be essentially permanent, and related components would not be removed.

Lands affected by pipeline construction would be reclaimed within days after disturbance. On private lands, reclamation procedures would be at the landowner's discretion.

### Water Pipelines

Where soil exists along the pipeline routes, it would be removed prior to construction, in two lifts, and the upper horizons (topsoil) would be segregated from the lower horizons (subsoil). Since the trench would be backfilled immediately after the pipe is in place, special topsoil stockpiling procedures would not be required.

In general, subsoil would be replaced over the pipe to within eight inches of the surface of the trench, and lightly compacted with a rubber-tired motor grader. Topsoil would then be filled in to form an eight-inch crown over the trench to compensate for normal subsidence.

Following backfilling and the construction of waterbreaks, the topsoil would be mulched with clean straw and seeded with the mixture described for the gasification plant. Seeding would take place in the fall after October 15. Seeding would be done with a drill where possible. In areas too steep for drill equipment, broadcast seeding at double the drill-seed rate would be used. Harrowing, brush dragging,



chaining, or hand raking would be used to cover the seed with soil. At temporary pipeline construction sites and laydown areas where vegetation had been removed or severely damaged, the topsoil would be disced, mulched, and seeded.

Waterbreaks would be installed along the pipeline routes in accordance with the general guidelines in Table 3.6-5. Unstable soils might require closer spacing or the use of partially buried sandbags across the slope. A channel grade of 0.002 would be established from the waterbreak to the natural ground elevation. Waterbreaks would be constructed so they drain freely to the natural ground elevation. On slopes greater than 20 percent, stabilization would be accomplished by terracing.

All stream crossings would occur in sections of the channel that are straight and perpendicular to the pipeline. After construction, stream banks would be restored to approximately their original grade and sand-cement sacks, breakers, or riprap would be placed where necessary to prevent erosion.

#### Other Components

Prior to construction, topsoil would be removed from the sites of the water wells, Combs Reservoir dam, and the North Platte River intake structure, and stockpiled for use in reclamation. It is expected that stockpiled topsoil could be replaced in less than one year. Consequently no stockpile maintenance procedures, other than keeping the soil surface in a roughened condition, would be instituted.



TABLE 3.6-5

## WATERBREAK GUIDELINES, PROPOSED WATER PIPELINES

Grade	Waterbreak Interval (feet)
Less than 2 percent	200
2 to 4 percent	100
4 to 5 percent	75
Greater than 5 percent	50

## 3.7 PROJECT PIPELINE

General Description

Synthetic pipeline gas (SPG) produced in the gasification plant would be transported through a proposed 24-inch diameter, buried steel pipeline over a distance of 162 miles to the existing natural gas distribution system in Colorado. Under normal operation the pipeline would transmit 300 MMBTU of SPG at a plant discharge pressure of 1,200 psig. No compressor stations would be required along the route.

Presently proposed routing of the pipeline is shown in Figure 3.7-1. The pipeline would leave the coal gasification plant in a southeasterly direction through Converse and Platte counties. Within Platte County the line would intersect, and then parallel, an existing pipeline corridor heading south, and would continue in the corridor through Larimer County to a point approximately 4 miles north of Cheyenne, where it would leave the corridor to skirt Cheyenne to the east. The line would terminate at the Cheyenne Compressor Station of Colorado Interstate Gas Company in northwestern Weld County, Colorado.

Appendix B is a listing of all potential stream crossings by the proposed project pipeline and other project components.



Topsoil would be spread uniformly over the well construction sites, intake area, and the downstream face of the dam, to a minimum depth of one foot. The surface would be disced to tie the topsoil to the subsoil. On the dam face, a mulch netting would be secured over the soil to ensure its stability until vegetation has become established, and the area would be broadcast or hydro-seeded. Seeding techniques for the other areas would be similar to those described for the gasification plant.

### 3.7 PRODUCT PIPELINE

#### General Description

Synthetic pipeline gas (SPG) produced in the gasification plant would be transported through a proposed 24-inch diameter, buried steel pipeline over a distance of 162 miles to the existing natural gas distribution system in Colorado. Under normal operation the pipeline would transmit 300 MMSCFD of SPG at a plant discharge pressure of 1,200 psig. No compressor stations would be required along the route.

Presently proposed routing of the pipeline is shown in Figure 3.7-1. The pipeline would leave the coal gasification plant in a southeasterly direction through Converse and Platte counties. Within Platte County the line would intersect, and then parallel, an existing pipeline corridor heading south, and would continue in the corridor through Laramie County to a point approximately 6 miles north of Cheyenne, where it would leave the corridor to skirt Cheyenne to the east. The line would terminate at the Cheyenne Compressor Station of Colorado Interstate Gas Company in northwestern Weld County, Colorado.

Appendix B is a listing of all potential stream crossings by the proposed product pipeline and other project components.



### Construction Procedures

Construction of the SPG pipeline would disturb, at most, approximately 1,960 acres of land, assuming a 100-foot corridor. The work would take approximately 18 weeks, using two spreads.

The proposed final route design would be determined after a field survey of the centerline of the alignment; adjustments arising from this survey would not exceed approximately 1/4 mile. Existing roads would be used as much as possible by onground crews doing the survey, and no vegetation would be removed unless necessary to allow for the operation of surveying instruments. Survey crews would also plot topographic features that would affect pipeline construction. Additional information would be required on some features encountered to ensure construction of safe structures; for example, to ensure that river crossings are properly designed, flow volume, water use, and maximum scour depths would have to be determined.

Typically, pipelines are laid in a continuous operation by a "spread" consisting of equipment and crews handling various types of construction activities for a given pipeline segment. The following is a list of major activities, in order of occurrence:

- Clearing and grading of site
- Trenching for pipeline
- Stringing, lining, welding, and radiographic examination of pipe
- Coating and wrapping of pipe
- Lowering in pipe
- Backfilling trench
- Hydrostatic testing of pipeline
- Tie-in of pipeline to existing system
- Cleanup and revegetation of site



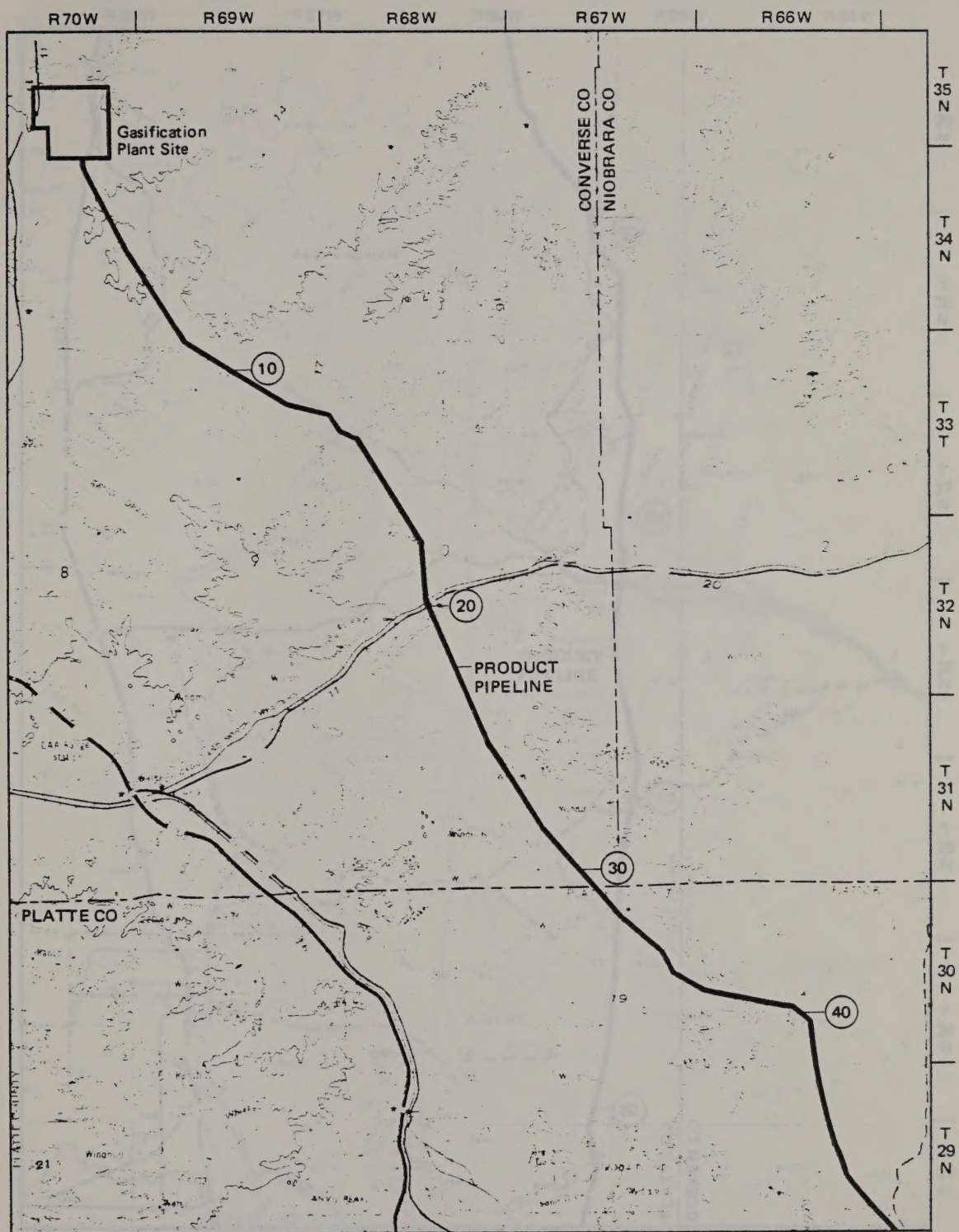


Figure 3.7-1(a)  
PRODUCT PIPELINE LOCATION







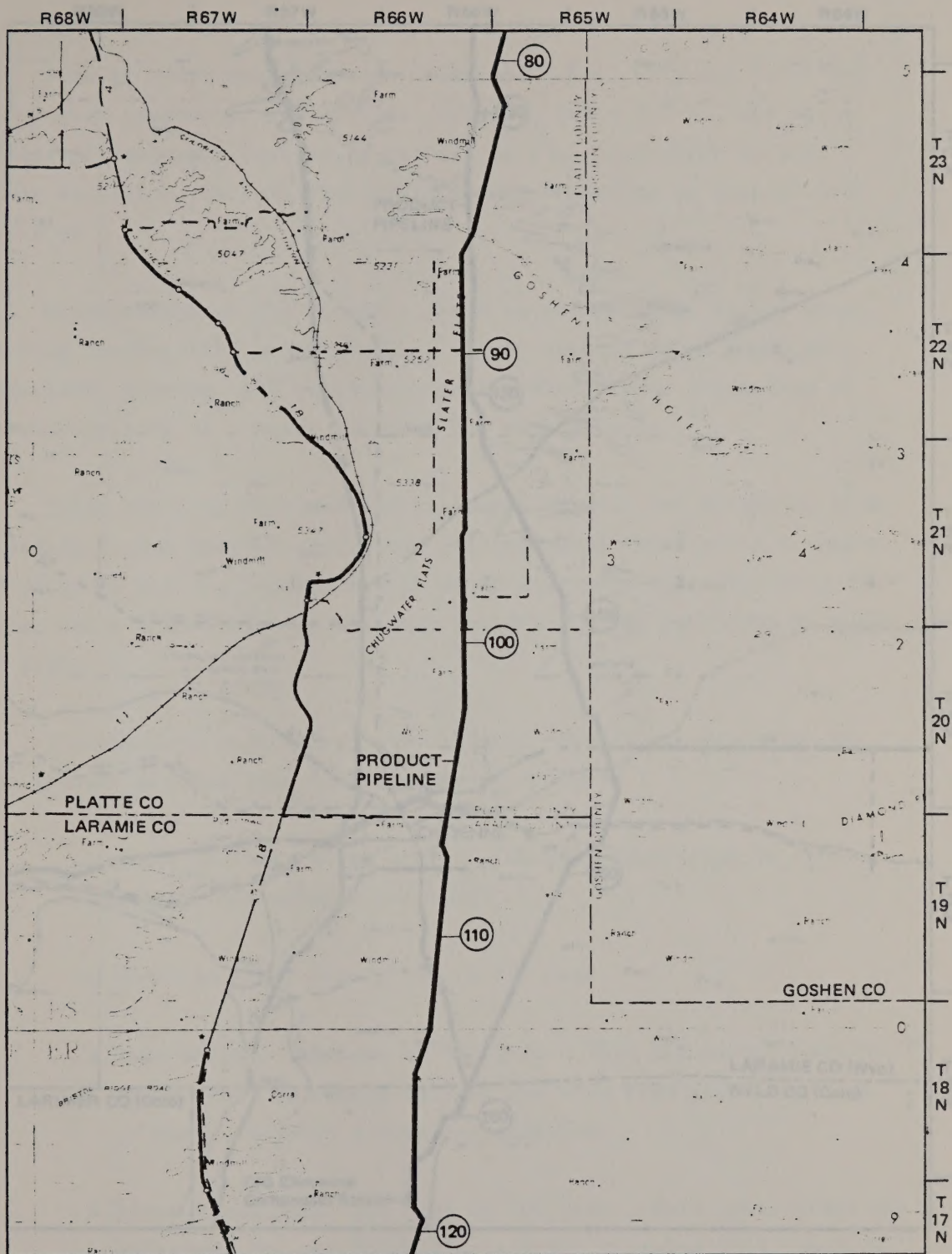


Figure 3.7-1(c)  
PRODUCT PIPELINE LOCATION



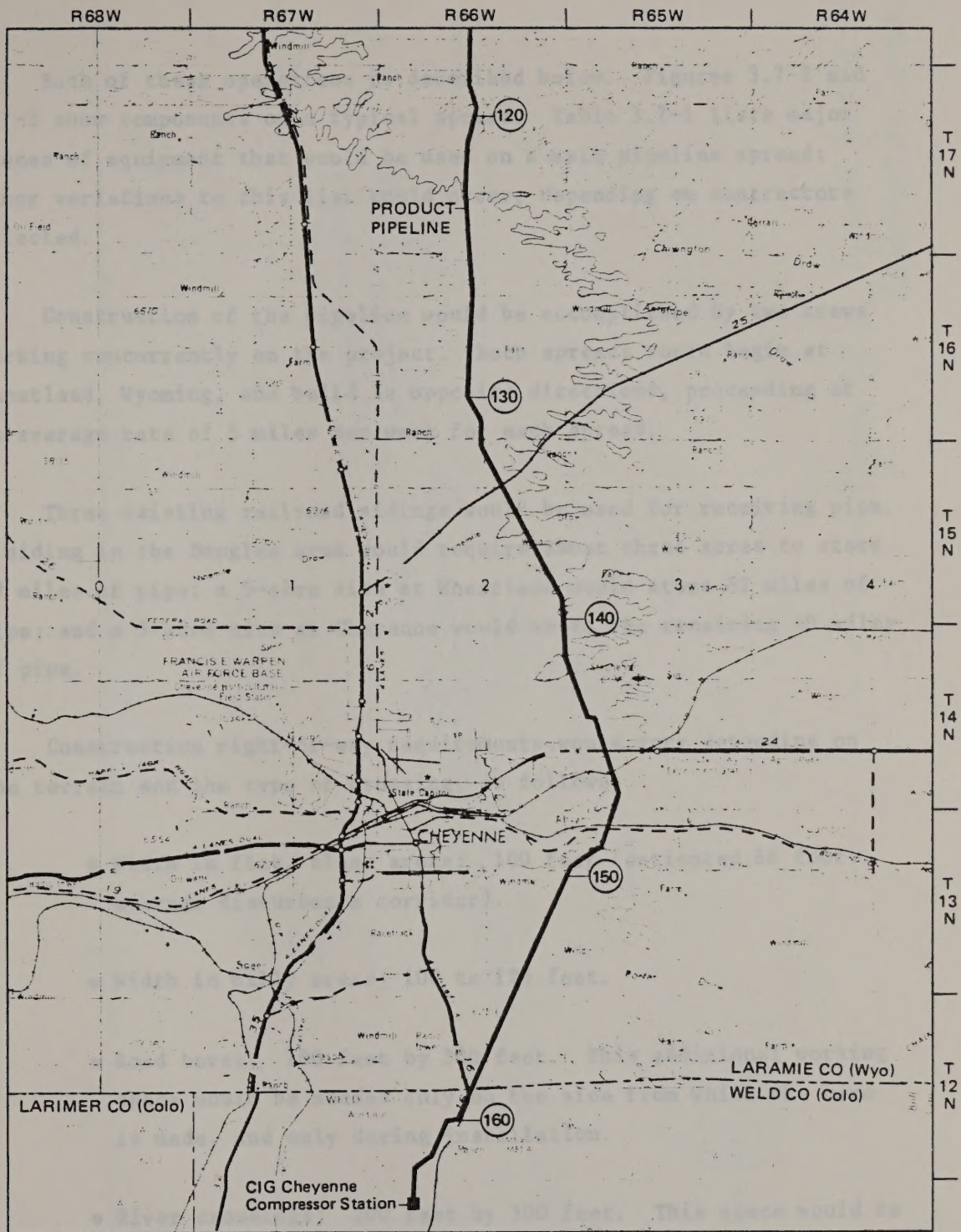


Figure 3.7-1(d)  
PRODUCT PIPELINE LOCATION



Each of these operations is described below. Figures 3.7-2 and 3.7-3 show components of a typical spread. Table 3.7-1 lists major pieces of equipment that would be used on a main pipeline spread; minor variations to this list could occur, depending on contractors selected.

Construction of the pipeline would be accomplished by two crews working concurrently on the project. Both spreads would begin at Wheatland, Wyoming, and build in opposite directions, proceeding at an average rate of 5 miles per week for each spread.

Three existing railroad sidings would be used for receiving pipe. A siding in the Douglas area would require about three acres to store 40 miles of pipe; a 5-acre site at Wheatland would store 82 miles of pipe; and a 3-acre site at Cheyenne would store the remaining 40 miles of pipe.

Construction right-of-way requirements would vary depending on the terrain and the type of crossing, as follows:

- Width in flat, clear areas: 100 feet (estimated 66 foot average disturbance corridor).
- Width in hilly areas: 100 to 125 feet.
- Road bores: 100 feet by 300 feet. This additional working space would be needed only on the side from which the bore is made, and only during installation.
- River crossings: 200 feet by 300 feet. This space would be necessary for the North Platte River crossing only; smaller streams would require less work space.



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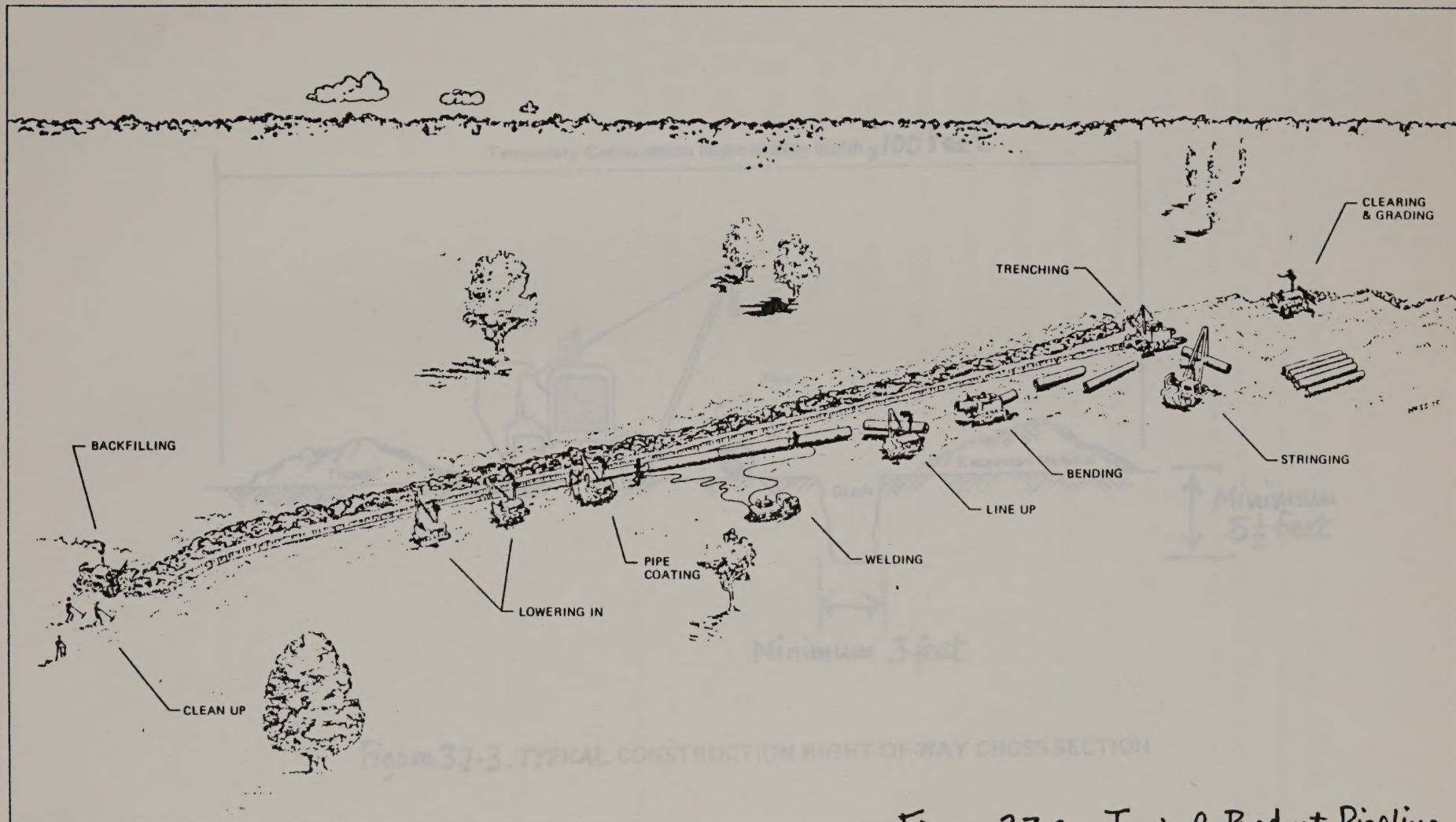


Figure 3.7-2. Typical Product Pipeline Construction Spread



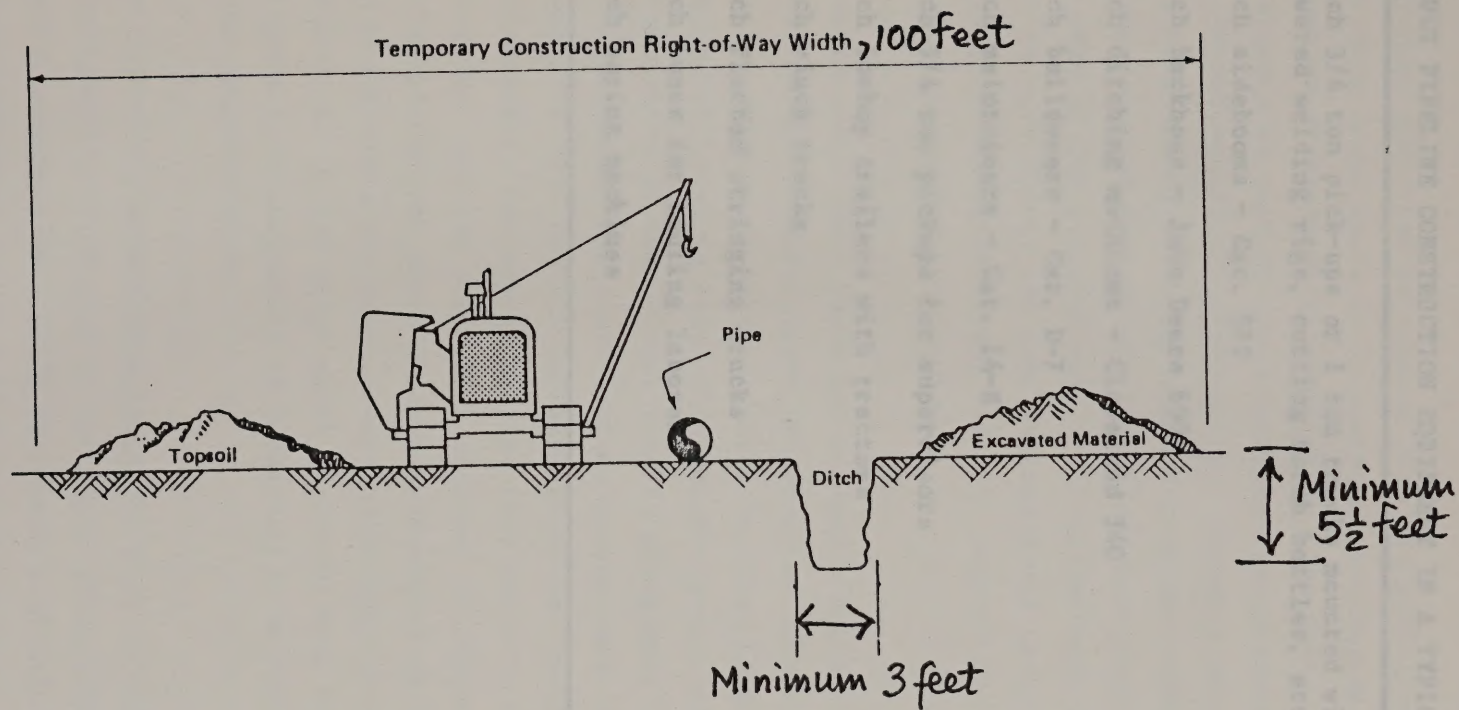


Figure 3.7-3. TYPICAL CONSTRUCTION RIGHT-OF-WAY CROSS SECTION



TABLE 3.7-1

## PRODUCT PIPELINE CONSTRUCTION EQUIPMENT IN A TYPICAL SPREAD

- 
- 16 each 3/4 ton pick-ups or 1 ton trucks mounted with gasoline powered welding rigs, cutting torch bottles, etc.
  - 8 each sidebooms - Cat. 572
  - 5 each backhoes - John Deere 690
  - 2 each ditching machines - Cleveland 340
  - 4 each bulldozers - Cat. D-7
  - 2 each maintainers - Cat. 14-E
  - 7 each 3/4 ton pickups for supervisors
  - 2 each lowboy trailers with tractors
  - 2 each winch trucks
  - 8 each flatbed stringing trucks
  - 2 each buses for hauling laborers
  - 2 each boring machines
-



Vegetation would not be removed from the entire right-of-way, but only from those areas where it is necessary to provide safe and efficient operation of construction equipment. The degree of vegetation clearing depends in part on the vegetation type present, but clearing would not extend beyond the right-of-way. Vegetation would be cleared from the 3-foot trench line, the storage area for excavated material, and the area required for vehicle travel and work space, and piled along the edge of the right-of-way. Soil disturbance would be small except in the pipe ditch, and root systems would be left intact. Trees growing in the right-of-way would be removed only as required for operation of construction equipment.

In remote areas where there are no access roads, the right-of-way itself would be the primary access for pipeline construction. To this end, temporary bridges or culverts would be constructed across creeks and arroyos on the working side of the right-of-way, when warranted, and where permitted by the federal surface management agency or the landowner. Where material would have to be cut away, the removed material would be used to fill in depressions and small valleys. Additional materials for approaches and fill would be obtained from the right-of-way, outside commercial sources, or adjacent lands, where permitted by the federal surface management agency or the landowner. In steep terrain where the right-of-way would have to be graded at two elevations, or in wet areas where diversion dams would be needed, the areas would upon completion of construction be contoured to resemble the original grade.

Where fences are encountered along the right-of-way, bracing would be installed at each edge of the right-of-way, fence wires would be cut, and a temporary gate would be constructed that could serve, at the landowner's discretion, as a permanent fence section upon completion of construction.



Once the right-of-way was prepared, ditching operations would begin. Most of the ditch would be excavated mechanically with ditching machines, backhoes, draglines, and cranes with clamshell buckets. Hand digging would be used to locate buried utilities, such as pipelines and cables. Generally, ditching operations would use ditching machines in open areas and backhoes near rivers and in tight areas; in areas of loose or unconsolidated rock, the ditch line would be ripped mechanically.

If the material encountered could not be ripped, it would be blasted. Unconsolidated material would be removed from the ditch-line end and a series of holes would be drilled by air-powered drills, typically suspended from a side-boom tractor. If blasting is necessary, the following safety precautions would be taken:

- In areas of human use, shots would be blanketed (matted).
- Landowners or tenants in close proximity to the shot would be notified in advance so that livestock and other property could be adequately protected.
- Before detonation, a clearance would be made to ensure that construction personnel, equipment, and local residents are in no danger.

Topsoil would be saved, subject to agreements with landowners and the surface management agency, and cast to the working side of the right-of-way. Ditch spoil would be cast to the opposite side so that the two soils do not mix; see Figure 3.7-3. Upon completion of construction, the ditch would be backfilled, with the topsoil going in last.



Ditch depth would vary with the conditions encountered. The cover from the top of the pipe to ground level would be a minimum of 42 inches. In traversing lands where there are known plans to level the land for irrigation or other purposes, the pipeline would be buried at a depth that would permit the land to be leveled and still provide ample cover. Where the pipeline would cross canals, burrow ditches, or irrigation ditches that are dredged to maintain depth, the ditch would be deep enough to permit safe dredging operations.

Ditching operations would be timed to minimize open-ditch conditions. Where an open ditch would cross range-animal paths, driveways, or rural roads, temporary crossings such as plank bridges or unexcavated ditch line would be provided for safe and unimpeded passage.

At river crossings, the proposed pipeline would be buried in a trench. Vegetation would be cleared on each bank of the river only as necessary to provide sufficient room for work space and equipment storage. Stream crossings would be made during periods of low flow whenever possible. Banks would be reclaimed to their original profile whenever possible and would be stabilized and vegetated as described below.

Ditches at river crossings would be deep enough that high water would not affect the pipe through scour action. The sag bends on either side of the river would be far enough from the river bank to ensure that water erosion would not expose them. Stream gradient would be maintained by removing all spoil from the bed upon completion of construction. Sand-cement sacks, breakers, or riprap would be placed over the pipeline where necessary. The pipeline would be weighted where it is underwater, to ensure that it remains in the ditch.



Generally, roadbeds supporting paved roadways or railroad tracks would be crossed by boring a hole beneath the bed rather than by ditching across the surface. The cutting head (bit) of the auger would be slightly larger than the casing pipe or line pipe, and the pipe would advance as the auger advances. Casing would be installed at all crossings where required by federal, state, or local authorities or by the railroad owner.

Pipe welding would be conducted in accordance with Department of Transportation Regulation 192.221. All completed welds would be visually inspected before the application of pipe coating. The frequency of radiographic inspection would meet or exceed Department of Transportation Regulation 192.243. For sections of pipe to be placed beneath railroads, highway rights-of-way, and rivers, all welds would be radiographically inspected before installation.

The pipe would be coated, wrapped as necessary, and lowered into the ditch. Backfilling, using the excavated material, would be done so as to ensure that the space below and beside the pipe is completely filled. Backfill material that could not be placed in the ditch would be crowned on top of the ditch to compensate for future settling. Salvaged topsoil would be moved to the top of the ditch line. Once the ditch was backfilled, the right-of-way and other affected areas would be cleaned up, graded, and reseeded, and fences repaired.

Cathodic protection rectifiers would be mounted on poles adjacent to the right-of-way, with the associated anodes buried with test leads exposed at the surface. Exact locations of cathodic protection devices would be determined after the pipeline is installed and tested.

The entire pipeline would be hydrostatically tested in accordance with CFR 192, "Subpart J, Test Requirements." Test water would be



obtained from rivers, creeks, or privately owned irrigation wells or canals, through agreements negotiated with local authorities controlling the water resources. Test water would be reused in successive pipeline segments, and would be released in accordance with federal, state, and local agency requirements governing discharge points, release rates, and water quality. Based on two spreads, each approximately 20 miles long, and assuming reuse of test water in successive spreads, the estimated maximum amount of water that would be required for testing is 15 acre-feet; the precise amount depends on the chosen testing procedures.

#### Operation and Maintenance

A work force of six people would operate the pipeline. The staff would consist of an area foreman, a measurement technician, two fieldmen and two repairmen, based in Douglas.

The right-of-way would be inspected approximately once a week by an aerial patrol. Valves and other above-ground facilities would be located next to roadways so that off-road traffic would be limited to emergency repairs on the pipeline or erosion-control devices. Corridor maintenance would be required only to prevent growth of trees over the line. Because of the current vegetative composition of the selected route it appears that little maintenance would be necessary.

#### Abandonment and Reclamation

All lands to be disturbed by project activities would be reclaimed to a productive condition consistent with past and present uses of the area. Lands affected by product pipeline construction would be reclaimed within days after disturbance. On private lands, reclamation procedures would be at the landowner's discretion. Procedures would be essentially identical to those described for water pipelines in Section 3.6.



All above ground structures would be cleaned, primed, and painted with two coats of finish paint to blend in with the surrounding landscape; colors would be equivalent to Pittsburgh Paint and Glass "Sagebrush Gray-Green" PPG #33, and Wilko Sandstone. A guard fence prefabricated from one inch structural steel tubing would be installed around all above ground facilities and a three inch thick layer of rock, purchased commercially, would be spread inside this fencing. All appurtenances would be installed with underground concrete support blocks and in such a manner as to prevent settlement.

The product pipeline would be left in place after project termination. It is likely that the pipeline would be incorporated into another transmission system. However, if it is not reused, the pipe would eventually deteriorate, resulting in some probable subsidence along the right-of-way.

### 3.8 ELECTRICAL SUPPLY SYSTEM

#### Coal Gasification Plant

Construction. The peak electric power requirement for construction of the proposed gasification plant would be provided from the existing 34.5 kV, 3-phase distribution system of Pacific Power and Light Company (PP&L). A new feeder line would tap the existing system in the northeast corner of T. 35 N., R. 70 W., sec. 16, and extend roughly south to a main construction substation within the facilities area of the plant site, a distance of about 3 1/4 miles; refer to Figure 3.3-1. The right-of-way for this feeder would be 20 feet wide, and would require no maintenance. Poles would be wood frame construction, with raptor protection, as shown in Figure 3.8-1. Additional temporary substations at the facilities area would transform delivered power to 13.8 kV and 480 V for distribution.



Operation. During normal operation, all power requirements of the gasification plant itself would be met by on-site generation from coal fines. The feeder line to the site and the main construction substation would be retained as an emergency back-up electrical source; all temporary construction substations and distribution lines would be dismantled upon completion of construction.

#### Railroad

Construction. Electric power for construction of the proposed electric railroad would be furnished at the gasification plant site, where rail sections would be welded into 2000-foot lengths prior to placement. All other electrical requirements would be provided by portable generators along the rail route.

Operation. Because of the single-phase, peaking load requirements of the electric railroad, power would be from a utility substation, rather than from on-site generation at the plant. The project would take delivery of 230 kV, 3-phase power from PP&L at the utility's substation on the west side of State Highway 59, in the NE 1/4 SW 1/4 of T. 36 N., R. 70 W., sec. 9 (see Figure 3.5-1). A substation would be constructed by WyCoalGas, Inc., alongside the utility's substation, to convert this supply to 50 kV, 1-phase power suitable for railroad operation; this project substation would be 1/4 acre in area and would be fenced. The 50 kV power would be transmitted east across the highway to the railroad conductors by an 800-foot overhead 4-conductor line.

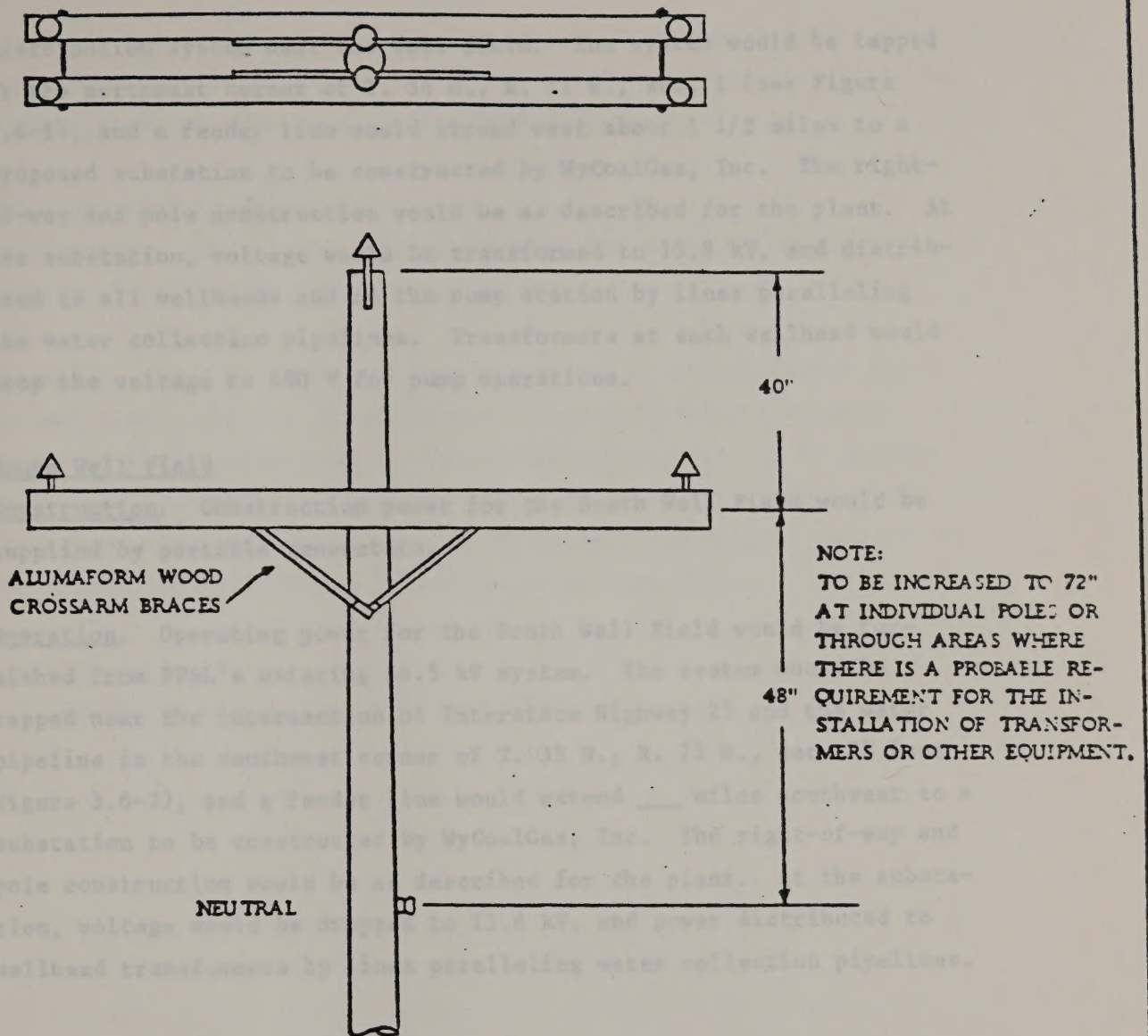
#### North Well Field

Construction. Construction power for the North Well Field would be furnished from portable generators.

Operation. The power supply for operation of all facilities within the North Well Field permit boundary would be PP&L's existing 34.5 kV



- Two of these structures would be used on a river crossing, one on each side of the river.



**NOTE:**

THIS CONSTRUCTION TO BE USED IN ALL AREAS WITH A KNOWN RAPTOR POPULATION OR WHEN SPECIFICALLY REQUIRED BY GOVERNMENTAL AGENCIES OR PROPERTY OWNERS.

**Figure 3.8-1.  
Electrical Power Pole  
with Raptor Protection**



distribution system near the well field. The system would be tapped at the northeast corner of T. 34 N., R. 71 W., sec. 1 (see Figure 3.6-1), and a feeder line would extend west about 1 1/2 miles to a proposed substation to be constructed by WyCoalGas, Inc. The right-of-way and pole construction would be as described for the plant. At the substation, voltage would be transformed to 13.8 kV, and distributed to all wellheads and to the pump station by lines paralleling the water collection pipelines. Transformers at each wellhead would drop the voltage to 480 V for pump operations.

#### South Well Field

Construction. Construction power for the South Well Field would be supplied by portable generators.

Operation. Operating power for the South Well Field would be furnished from PP&L's existing 34.5 kV system. The system would be tapped near the intersection of Interstate Highway 25 and the water pipeline in the southwest corner of T. 33 N., R. 73 W., sec. 28 (see Figure 3.6-2), and a feeder line would extend \_\_\_\_ miles southwest to a substation to be constructed by WyCoalGas, Inc. The right-of-way and pole construction would be as described for the plant. At the substation, voltage would be dropped to 13.8 kV, and power distributed to wellhead transformers by lines paralleling water collection pipelines.

#### Diversion Facility and Combs Reservoir

Construction. Construction power for the proposed diversion facility and Combs Reservoir would be supplied by portable generators.

Operation. Operating power would come from PP&L's existing Orpha substation in the SE 1/4 of T. 33 N., R. 72 W., sec. 10. A feeder line at 34.5 kV would be constructed from the Orpha substation, easterly about 3 miles to the diversion site in the SE 1/4 of T. 33 N.,



R. 71 W., sec. 7 (see Figure 3.6-3). The right-of-way and pole construction would be as described for the plant. A substation would be incorporated into the pump station when completed.

#### Water and Product Pipelines

Construction. All electrical requirements for pipeline construction would be furnished by portable generators.

Operation. Pump stations would represent the only significant operational power need for the pipelines. The product pipeline would require a single compressor at the gasification plant, to be powered by on-site generation. The water transmission system would include three pump stations, one within the North Well Field power network and two within the North Platte Diversion power network.

#### Rochelle Mine

(Awaiting information from Rochelle Coal Company)



## Chapter 4

## AUTHORIZING ACTIONS

Major federal, state, and local approvals associated with environmental concerns that would have to be obtained before the proposed action could be implemented are presented below.

## FEDERAL

Department of the Interior

Bureau of Land Management (BLM). The BLM Wyoming State Office is responsible for the preparation of the environmental impact statement and for the issuance of grants of right-of-way (ROW) across lands under its jurisdiction. The ROW grants would be issued under the authority of Title V of the Federal Land Management Policy Act (FLPMA), as defined in 43 CFR 2800. WyCoalGas has submitted applications for two right-of-way permits, serial numbers W47428 and W64644.

Temporary use permits for additional construction space, storage sites, major drainage crossings, highway and railroad crossings, and other utility crossings would be issued from the appropriate BLM district office under the authority of Title V of FLPMA, as defined in 43 CFR 2920.

The BLM is also responsible for the issuance of an undetermined number of noncompetitive (negotiated) sales of mineral material (commercial fill, sand, and gravel, and other surfacing or construction material of common variety) under 43 CFR 3611, Noncompetitive Sales.

Office of Surface Mining (OSM). Under the Surface Mining Control and Reclamation Act of 1977 (P.L. 95-87), the coal mining and reclamation plan will be reviewed by OSM and the Wyoming Department of Environmental Quality (DEQ). Under the authority of the Mineral



Leasing Act, as amended, the OSM approves or recommends coal mining actions on federal lands.

Geological Survey (USGS). Development, production, and coal resource recovery requirements in the mining permit are approved by USGS as stipulated in the Mineral Leasing Requirements of 1920, amended 1976 by the Federal Coal Leasing Act of 1978, and 30 CFR 211.

Fish and Wildlife Service (FWS). The FWS is responsible for providing consultation to the BLM concerning the possible effects of the proposed action on fish and wildlife as required by Section 10 of the Wildlife Coordination Act; Section 7 of the Endangered Species Act of 1973, as amended; the Migratory Bird Treaty Act (Sec. 3, 40 Statute 755, 16 USC 704); the Bald Eagle Act of 1940 (Title 54, Statute 250); and the Wild Horse and Burro Act (P.L. 92-195). Consultation on threatened and endangered species will be initiated and conducted in accordance with 50 CFR 402, Interagency Cooperation, Endangered Species Act of 1973.

#### Department of Agriculture

Forest Service (FS). In accordance with Title V of FLPMA as defined in 36 CFR 251, the Forest Service is responsible for issuing a special use permit for approximately 4.5 miles of the electric railroad right-of-way that would cross the Thunder Basin National Grassland. Temporary use permits for mineral materials (e.g., fill, sand, and gravel) and for storage or overstripping are issued by the FS. The Forest Service must also review the coal mine and reclamation plan and consent to permit issuance prior to OSM and state approval as defined in 30 CFR 741.

#### Federal Energy Regulatory Commission (FERC)

Under Section 7 of the Natural Gas Act, FERC has the authority to issue or deny a Certificate of Public Convenience and Necessity prior



to the interstate sale and/or transportation of natural gas. The issuance of the certificate is dependent on customer service needs, project financing, and design feasibility.

#### Department of the Army

Corps of Engineers (COE). Under Section 404 of the Clean Water Act of 1977 (40 CFR 122-123), implemented by COE regulations (33 CFR 323), construction of the intake structure on the North Platte River and all river and stream crossings would be permitted under the nationwide permit for utility lines (33 CFR 323), provided that the conditions of this permit are met. However, the Corps does have discretionary authority to require individual permits for some or all pipeline crossings if the District Engineer determines that the concerns of the aquatic environment indicate a need for such action (33 CFR 323.4-4).

#### Environmental Protection Agency (EPA)

EPA's regulatory authority over the proposed project would be based on regulations implementing the Resource Conservation and Recovery Act (RCRA) of 1976. EPA has given authority for the state to administer federal air and water regulations.

#### Advisory Council on Historic Preservation (ACHP)

Section 106 of the Historic Preservation Act of 1966, as amended, requires that the President's Advisory Council on Historic Preservation have an opportunity to comment on any undertaking that affects cultural resources listed in or eligible for the National Register of Historic Places. Executive Order 11593 (Protection and Enhancement of the Cultural Environment) mandates that all executive branch agencies, bureaus, and offices (1) compile an inventory of the cultural resources for which they are trustee; (2) nominate all eligible government properties to the National Register of Historic Places; (3) preserve and protect their cultural resources; and (4) ensure that



agency activities contribute to the preservation and protection of non-federally-owned cultural resources. The Advisory Council implements these regulations through the process outlined in 36 CFR 800 (Protection of Historic and Cultural Properties).

#### Wyoming Board of Control/State Engineer

STATE

Under Wyoming Statutes 41-3-301, 41-3-903, and 41-4-301, the

Wyoming State Engineer is responsible for issuing permits for appro-

#### Wyoming Industrial Siting Council

Under the Industrial Development Information and Siting Act of 1975 (Wyoming Statute 35-12-101), a Wyoming Industrial Siting Act permit must be obtained for construction of all project components except the mine.

#### Wyoming Department of Environmental Quality

Air Quality Division. The Air Quality Division administers and enforces federal Prevention of Significant Deterioration (PSD) regulations, ambient air quality standards, federal visibility regulations and state air quality regulations. Under Section 21 of the Wyoming Air Quality Standards and Regulations, air quality permits are required for the construction and operation of the proposed project.

Water Quality Division. Under Wyoming statutes 35-11-301 (a.i) and 35-11-301 (a.iii), the Wyoming Water Quality Division issues a National Pollutant Discharge Elimination System (NPDES) permit to construct, install, or modify public water supplies and waste water facilities.

Land Quality Division. This division, with the approval of OSM, regulates surface coal mining and reclamation activities under the Surface Mining Control and Reclamation Act of 1977, the Wyoming Environmental Quality Act of 1973, as amended, and the Land Quality Rules and Regulations of 1980.



Solid Waste Program. Approval of waste disposal facilities must be obtained from the solid waste management supervisor, in accordance with Wyoming Statute 35-11-502.

Wyoming Board of Control/State Engineer

Under Wyoming Statutes 41-3-301, 41-3-905, and 41-4-501, the Wyoming State Engineer is responsible for issuing permits for appropriation of surface water and ground water and for constructing a dam or reservoir to impound or store water.

Wyoming State Highway Commission

Permits must be obtained from the Wyoming Highway Commission to cross state roads. The Highway Commission is also responsible for issuing a utility license to conduct construction activities in a highway right-of-way.

Wyoming State Historic Preservation Office (SHPO)

As stipulated in the National Historic Preservation Act of 1966 as amended, EO 115.93, 36 CFR 60, 36 CFR 800, and 36 CFR 1213, consultation with the SHPO is required on matters affecting historical and archeological resources.

Colorado State Highway Commission

Permits must be obtained from the Colorado Highway Commission to cross state roads.

OTHER JURISDICTIONS

WyCoalGas is responsible for identifying and applying for special use and other permits from local and regional districts and jurisdictions. Permits may be needed from authorities such as irrigation and water conservation districts, drainage districts, and counties. Other jurisdictions would be responsible for issuing easements and permits as appropriate.



TABLE 5.1-1

IDENTIFIED ALTERNATIVES TO THE PROPOSED ACTION

Plant

Plant located in the Midwest CHAPTER 5 Missouri River in Iowa or Missouri.

ALTERNATIVES TO THE PROPOSED ACTION

Nine-month plant sites.

Other coal gasification processes.

5.1 INTRODUCTION

Single stage plant construction schedule.

Alternatives to the proposed action that have been considered for this environmental assessment are listed in Table 5.1-1. Many of these alternatives were identified by WyCoalGas during the conceptual development and preliminary design of the proposed action. Others were identified through the public scoping process and interagency coordination. Finally, alternatives were identified by those (see Section 4.3 of the EIS) who participated in the preparation of this statement.

Three criteria were used to select reasonable alternatives to the proposed action for detailed impact analysis. These criteria are:

Permitted coal mines in the Powder River basin as a source for

1. The alternative must provide a reasonable alternative to the proposed action. Alternatives which did not meet the purpose of the proposed action or were not reasonably available in the region under consideration were screened from detailed analysis. Reasonable alternatives also had to be technically possible; a process or technique was considered possible if it had been proven feasible in full operation or had been proven commercially successful and was in an advanced stage of development.



TABLE 5.1-1

## IDENTIFIED ALTERNATIVES TO THE PROPOSED ACTION

Plant

Plant located in the Midwest along the Missouri River in Iowa or Missouri.

Mine-mouth plant sites.

Other coal gasification processes.

Single stage plant construction schedule.

Cooling process streams exclusively with water.

Combustion of coal fines at the plant to produce electricity.

Disposal of ash at the plant site.

Storage of ammonia byproduct in a gaseous state.

Storage of sulfur byproduct in a solid state.

Process water obtained from agricultural appropriation.<sup>b</sup>

Coal Supply

Illinois coal reserves as a source for the gasification plant.

Permitted coal mines in the Powder River basin as a source for the gasification plant.

Underground and auger mining.

Transportation of coal to the plant via diesel train, slurry pipeline, conveyor belt, or trucks.

Transportation of coal<sup>a</sup> to the plant via existing Burlington Northern Railroad.



TABLE 5.1-1 Concluded

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Water Supply System

Substitution of groundwater for the North Platte River flood appropriation.<sup>a</sup>

Process water obtained from oil and gas production water, municipal waste water, or from the Oahe Reservoir.

Transportation of water from LaPrele Reservoir to Combs Reservoir by pipeline.

Product Pipeline

Alternatives routes:

- North to Ashland, Montana
- North to Dickinson, North Dakota
- Southeast to Louisburg, Kansas (three alternatives)
- South-southeast to Liberal, Kansas (two alternatives)
- South to west side of Cheyenne

Pipeline Diameter

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<sup>a</sup> Selected for detailed analysis.

<sup>b</sup> This alternative is currently under consideration; detailed analysis is not completed.



TABLE 5.1-2

2. The alternative allows procurement of required permits for project implementation. Alternatives which would clearly cause the denial of an environmental permit to construct and/or operate one or more of the project components were screened from detailed analysis.
3. The alternative represents an action which is clearly better than the proposed action in terms of fewer adverse environmental impacts.

Judgments as to whether the criteria were satisfied in each case were based on professional experience. Table 5.1-2 identifies the criteria by which particular alternatives were eliminated from detailed analysis. Further discussion of the alternatives that were screened out is provided below.

## 5.2 ALTERNATIVES ELIMINATED FROM DETAILED ANALYSIS

### Coal Source

Midwest. Panhandle Eastern Pipe Line Company's present pipeline system originates in southwest Kansas and the panhandle regions of Texas and Oklahoma, and extends across the Midwest to Michigan. Due to their proximity to this pipeline system, Illinois coal reserves were considered as a source for the proposed gasification plant. However, eastern coals in general, including those in Illinois, are caking coals which are either not suitable, or offer a greater technical risk, for use in the Lurgi gasification process. Caking coals would clog the grates at the bottom of the gasifiers where ash is removed from the vessels. In order to use this type of coal in the process it would be necessary to reduce throughput to uneconomical levels.



TABLE 5.1-2

## SUMMARY OF SCREENING DECISIONS FOR ALTERNATIVES

Alternatives	Criteria for Screening <sup>a</sup> from Detailed Analysis <sup>a</sup>		
	1	2	3
Midwest Plant	X		
Mine-Mouth Plant Sites		X	
Gasification Processes	X		
Single Stage Plant Construction			X
Plant Water Cooling	X		X
Ash Disposal at Plant		X	
Excess Electricity from Coal Fines			X
Gaseous Ammonia Storage			X
Solid Sulfur Storage			X
Illinois Coal Source	X		
Permitted Powder River Basin Mines			X
Underground Mining	X		X
Auger Mining	X		
Coal Transport by Diesel Train			X
Coal Transport by Slurry Pipeline	X		
Coal Transport by Conveyor Belt	X		X
Coal Transport by Truck	X		X
Process Water from Oil and Gas Production	X		
Process Water from Municipal Waste water	X		
Process Water from Oahe Reservoir	X		X
Product Transport from LaPrele Reservoir	X		X
Product Pipeline Routes			X
Pipeline Diameter	X		X

<sup>a</sup>Key to Criteria:

- 1 = The alternative does not provide a reasonable alternative to the proposed action.
- 2 = The alternative prevents procurement of a required permit for project implementation.
- 3 = The alternative does not provide an action which is clearly better than the proposed action in terms of environmental impacts.



Powder River Basin. Coal from the Powder River Basin was chosen by WyCoalGas as a source for the plant because it is within a reasonable distance of the existing pipeline system and it has suitable characteristics for gasification in the Lurgi process. In addition to the proposed action of using coal from the Rochelle Mine, permitted mines in the Powder River Basin were also considered as a source for the plant.

There are approximately nine active mines, five permitted mines, and one proposed mine in an advanced stage of permitting in the Basin. As discussed above, the proposed plant would require approximately 10.2 million tons/year of coal at full operation, or a total of approximately 306 million tons over the 30-year life of the project. A review of the mine projects in the region indicates that the existing Rawhide and Black Thunder mines and the proposed Caballo Mine have sufficient undedicated reserves to meet the plant requirements.

Rochelle Coal Company plans to open the Rochelle Mine and market the coal whether or not the proposed plant is approved; therefore, the use of coal from alternative mines would not result in abandonment of development plans. For this reason, the alternatives must be evaluated on their individual merit. Since the physical and biological environments are relatively uniform over the portion of the Powder River Basin where the alternative mines are located (U.S. Department of Interior 1979 and 1981), the major environmental difference among the mines are the emissions resulting from the transportation of coal to the proposed plant site. It can be reasonably assumed that the mode of transportation would be identical for all of the mines (see the discussion of coal transportation alternatives below); therefore, emissions would be a direct function of haul distance to the proposed plant. All of the permitted mines with sufficient reserves to meet the needs of the plant are located further from the plant site than



the proposed Rochelle Mine; therefore, these alternatives were eliminated from further consideration.

The proposed Antelope Mine is the only permitted mine in the Basin that is closer to the plant site than is the Rochelle Mine. Even if the Antelope Mine were expanded to meet the plant requirement, these two mines are close enough to each other that the reduction in transportation-related emissions would not be large enough for the Antelope Mine to be a clearly better alternative in terms of environmental impacts.

#### Plant Site

Midwest. Selection of a plant site by WyCoalGas included a review of sites in the Midwest along the Missouri River in Iowa and Missouri as well as sites near the coal source in Wyoming. The Midwest was considered because of the availability of water and labor.

It would be necessary to transport the coal and ash between a Wyoming mine and a plant in the Midwest by rail (refer to the discussion on coal transportation and ash disposal alternatives below). The environmental impacts associated with rail transport of coal and ash over a distance of at least 500 miles would be significantly greater than rail transport of these materials over roughly 40 miles and the subsequent shipment of gas by pipeline from the plant to an intertie with the existing pipeline system. The product pipeline in the proposed project would normally cause only temporary construction-related impacts since the pipeline would be buried and the right-of-way revegetated, normal surveillance and maintenance would not require significant surface disturbance, and no new compressor stations would be installed. Long-distance transport of coal and ash by rail would probably require a greater long-term commitment of land to the project since it is expected that more than 40 miles of additional rail line



would have to be constructed. In addition, increased air emissions and an increased loss of wildlife are likely.

It is also likely that project reliability would be reduced as a result of siting the plant in the Midwest. Assuming that the unit trains used to supply such a plant would consist of 90 to 100-ton capacity cars, roughly three trains would be required each day, six days per week. Over a distance of approximately 500 miles, an average of four derailments could occur in a year. Approximately one derailment per year could occur on the proposed electric railroad between the Rochelle Mine and the proposed plant site, and an accident which would cause a leak in the proposed product pipeline could occur on the average of once every 3.7 years.

Wyoming. An area within approximately a 60-mile radius of the proposed Rochelle Mine was examined for possible plant sites. For flexibility in locating facilities, to allow for site-specific engineering considerations of foundation materials, topography, and drainage, a contiguous area of at least 2,400 acres is required for the plant site.

The study area is relatively uniform from the standpoint of geological, ecological, hydrological/water quality, and meteorological/air quality considerations (U.S. Department of Interior 1979 and 1981; U.S. Nuclear Regulatory Commission 1977). Therefore, these environmental parameters did not provide adequate screening criteria for plant siting.

In 1973 and 1974 when the plant site was selected, Gillette, located at the northern end of the study area, was experiencing severe socioeconomic problems due to rapid population growth associated with energy development. Corresponding conditions were not as severe in



the communities of Casper, Glenrock, and Douglas, at the southern end of the study area. For this reason, a plant site location which directed project-related population growth towards these southern communities was preferred. In addition, much of the land north of the Rochelle Mine and west of Highway 59 was eliminated from further consideration because it was either underlain by economically recoverable reserves of coal and other minerals, or owned by the state or federal government.

Three sites were selected within the study area for environmental, economic, and engineering design studies: a northern mine-mouth site (north site), a southeast mine-mouth site (east site), and a site near Douglas (south site) (Figure 5.2-1). Data collected during these studies are provided as Appendix C. The north and east plant sites were eliminated from further consideration because it would not be possible to obtain an air quality permit from the Wyoming Department of Environmental Quality to construct a mine-mouth facility. For this reason, mine-mouth plants at other permitted mines in the region were also eliminated from further consideration.

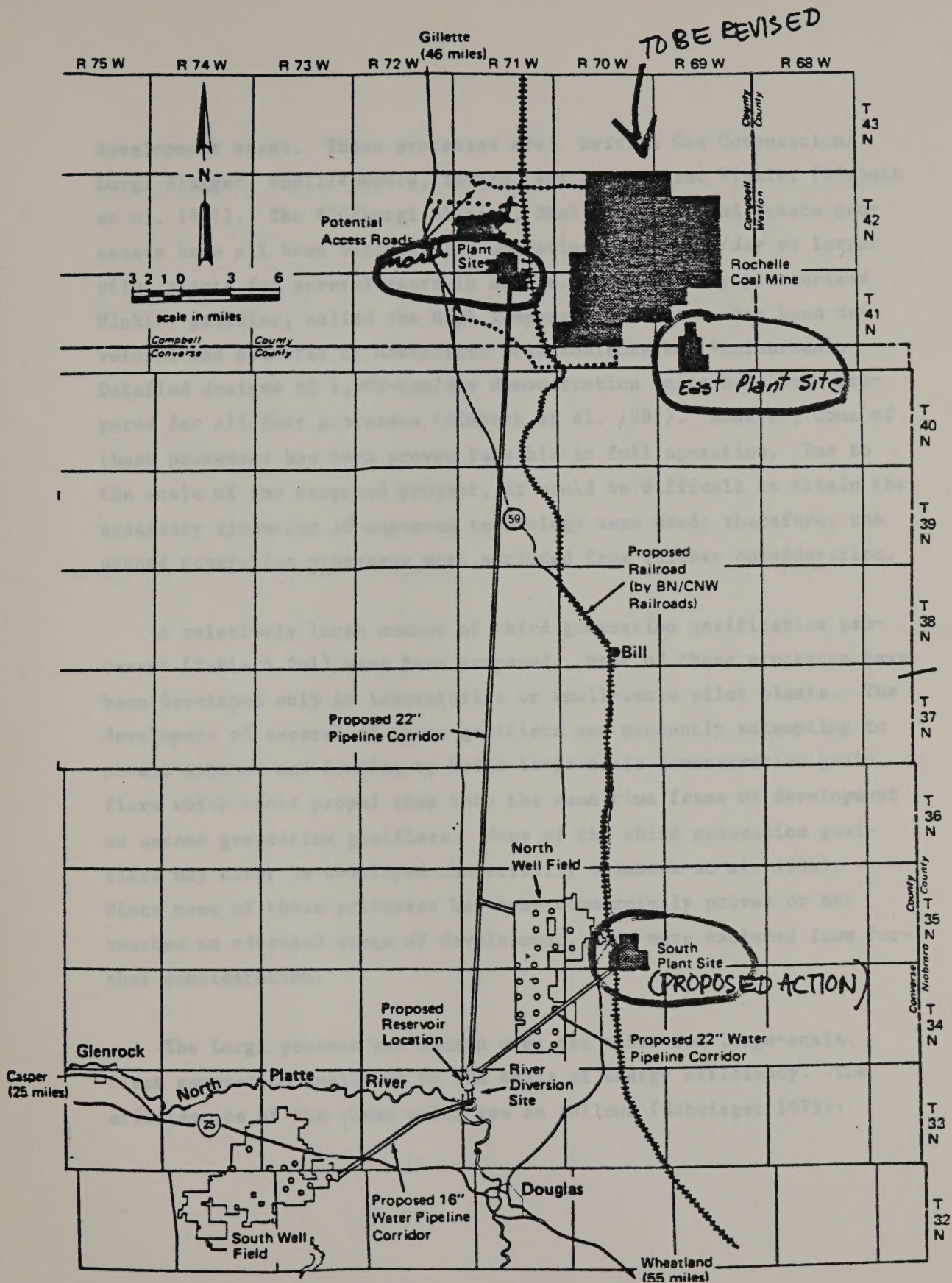
#### Gasification Process

There are only three large-scale, commercially proven coal gasification processes: Winkler, Lurgi, and Koppers-Totzek. The Wellman-Galusha gasification process is commercially proven (Schwieger 1979); but its design does not allow the construction of gasifiers large enough to economically produce large volumes of pipeline grade gas. It is estimated that roughly 140 Wellman-Galusha gasifiers would be required to produce the volume of high Btu gas proposed for this project.

Several second generation gasification processes, which are basically improvements of first generation gasifiers, are in the

Figure 5.2-1. Location of  
Alternative Plant Sites





**Figure 5.2-1. Location of Alternative Plant Sites**



development stage. These processes are: British Gas Corporation/Lurgi Slagger, Shell/Koppers, Texaco, and Pressurized Winkler (Simbeck et al. 1981). The BGC/Lurgi Slagger, Shell/Koppers, and Texaco processes have all been successfully operating in 150 ton/day or larger pilot plants for several years in Europe. A 25-ton/day pressurized Winkler gasifier, called the High Temperature Winkler, has been developed and operated by Rheinische Braunkohlenwerke (Rheinbraun). Detailed designs of 1,000-ton/day demonstration units have been prepared for all four processes (Simbeck et al. 1981). However, none of these processes has been proven feasible in full operation. Due to the scale of the proposed project, it would be difficult to obtain the necessary financing if unproven technology were used; therefore, the second generation processes were excluded from further consideration.

A relatively large number of third generation gasification processes (Table 5.2-1) have been proposed. Most of these processes have been developed only in laboratories or small-scale pilot plants. The developers of several of these gasifiers are presently attempting to obtain support and funding to build large scale demonstration gasifiers which could propel them into the same time frame of development as second generation gasifiers. Many of the third generation gasifiers may never be developed commercially (Simbeck et al. 1981). Since none of these processes has been commercially proven or has reached an advanced stage of development, they were excluded from further consideration.

The Lurgi process was chosen over the other two large-scale, first generation gasifiers on the basis of energy efficiency. The efficiencies of the three units are as follows (Schwieger 1979):



TABLE 5.2-1

## THIRD GENERATION COAL GASIFICATION PROCESSES

Gravitating Flow	Fluid Bed	Entrained Flow
High Pressure Lurgi	Exxon Catalytic	Saarberg/Otto
Gegas	Westinghouse	Bigas
Kilngas	Cogas	Rockwell/Cities Service
Underground	U-Gas	C. E.
KGN	Hygas	MRF/Eyring
BGC's Composite	Synthane	Bell Aerospace
BKV	Tri-Gas	AVCO
PCV	N.C.B.	VEW
		B. & W.

Source: Simbeck et al. 1981. Note: In the author's opinion these processes will generally not be available for commercial application until 1995.



<u>Process</u>	<u>Efficiency (%)</u>
Lurgi	76
Winkler	69
Koppers-Totzek	68

In addition to having a greater efficiency, the Lurgi gasifier produces gasifiable liquid hydrocarbons which are not produced in the other two units.

Approximately 40 percent of the gas produced from coal in the Lurgi gasifier is methane, while no methane is produced during initial gasification in the Winkler and Koppers-Totzek processes. For this reason, much more oxygen is required to produce methane in the Winkler and Koppers-Totzek processes than in the Lurgi process. This increased oxygen demand substantially increases the amount of electricity required for plant operation, further reducing the overall efficiency of the Winkler and Koppers-Totzek processes relative to the Lurgi process.

Both Winkler and Koppers-Totzek gasifiers operate at atmospheric pressures, requiring considerable compression of the product gas in order to ship it by pipeline. The Lurgi process is pressurized, which reduces the need for further compression of the gas, resulting in an overall decrease in the energy requirement of the plant relative to the other two processes.

#### Plant Construction Schedule

As noted in earlier sections, WyCoalGas proposed to construct the gasification plant in two stages. The construction labor force for the first stage would peak at 3,169 in 1985 while a maximum of 3,004 construction workers would be required in 1987 for the second stage.



The alternative of constructing the plant in a single stage was considered. The approximate labor force required for such a construction schedule, relative to the proposed action, is presented in Figure 5.2-2.

As discussed in Chapter Three of the Environmental Impact Statement, significant socioeconomic impacts would result from two-staged construction of the proposed plant. A single-stage construction schedule would significantly increase these impacts; therefore, this alternative was eliminated from further consideration.

#### Plant Cooling System

In order to minimize project water requirements, air cooling of process streams was incorporated into the plant design whenever possible. The alternative of cooling process streams exclusively with water was also considered.

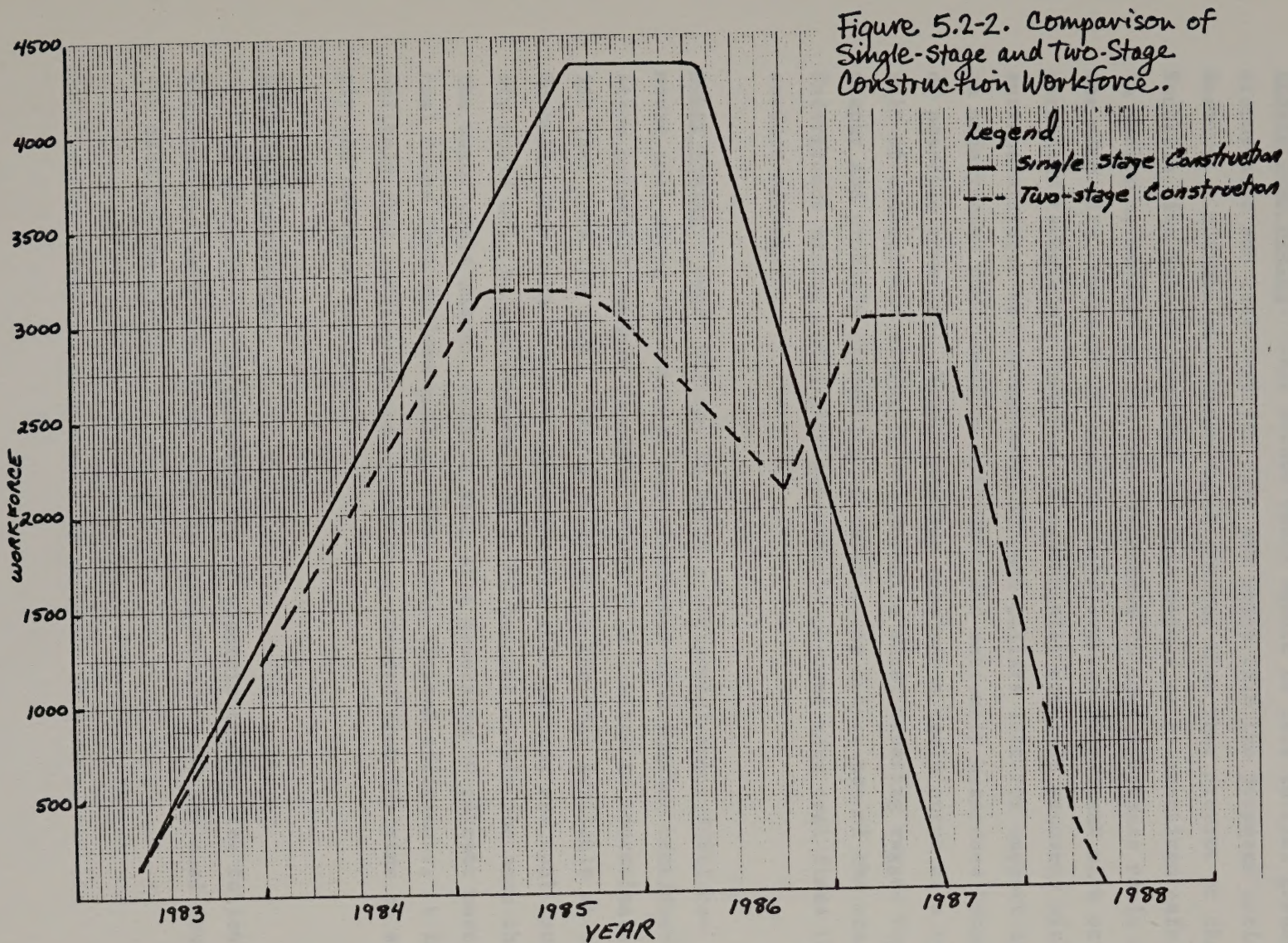
The quantity of water required for a conventionally water cooled gasification plant would be approximately 12,000 acre-feet per year. The use of total water cooling would not provide any environmental advantages over the proposed action. Consumptive use of 12,000 acre-feet per year of water in the semiarid region proposed for the plant site would result in greater environmental impacts than the proposed action. Consequently, this alternative was eliminated from further consideration.

#### Mining Method

Underground and auger mining were considered as methods for recovery of coal for use in the proposed plant.



5-15





Underground Mining. This method would result in less initial ground disturbance and less fugitive dust and noise than the proposed action. However, a minimum overburden depth greater than that present at the Rochelle Mine site is required for this method to be practiced safely. In addition, because of the low overburden to coal thickness ratio at the mine site, recovery of coal may only average 50 percent with underground techniques, compared to essentially complete recovery with surface mining. Future recovery of coal pillars left for support in an underground mine would be difficult and extremely hazardous because of possible cave-ins. Severe surface subsidence could occur as a result of underground mining at the Rochelle site, creating rugged topography and probably preventing or restricting future use of the area. Underground mining would also generate 50 percent more coal fines than surface mining.

Auger Mining. Auger mining, in which a horizontal auger drill removes coal along the outcrop, was eliminated from further consideration primarily because resource recovery is limited to approximately 200 feet into the seam. Only a fraction of the coal available at the Rochelle Mine site would be removed using this method, and coal recovery would only be approximately 50 to 60 percent within the zone that the auger could reach. Auger mining also generates 50 percent more coal fines than surface mining. With this limited efficiency, it is unlikely that sufficient coal could be recovered from the mine to supply the needs of the plant.

#### Coal Transportation

In addition to the proposed use of electric trains, the following alternatives were considered for the transportation of the coal from the mine to the plant:



- Diesel train
- Slurry pipeline
- Conveyor belt
- Trucks

Diesel Train. To equal the design capabilities of the proposed electric train system, diesel locomotives with a total output of 6,000 horsepower would be required. Emissions from the diesel engines would be significantly higher for most pollutants than those associated with the production of the electricity necessary for the proposed action (Table 5.2-2). In addition, diesel emissions would occur at ground level, while emissions from the electrical power plant would occur at a height of roughly 300 feet; consequently, ground level concentrations of all pollutants would be greater for diesel than for the electric train. Noise produced by diesel trains would also be significantly greater than from electric trains. For these reasons, the use of diesel trains to transport coal to the plant was eliminated from further consideration.

Slurry Pipeline. In order to transport coal via a slurry pipeline, the coal must be reduced in size so that it passes through at least a 14-mesh sieve (1.41 millimeters). The Lurgi gasifier cannot economically process coal finer than 1/8 inch in size. Consequently, the use of a coal slurry pipeline does not constitute a reasonable alternative to the proposed action.

Conveyor Belt. Conveyor belts longer than roughly five miles are not technically feasible. Therefore, it would be necessary to transfer the coal at least seven times between the proposed mine and plant if this system were used. Approximately two to three percent additional coal fines would be produced at each transfer point. Since these fines cannot be used in the Lurgi gasifiers, an additional 2



TABLE 5.2-2

COMPARISON OF EMISSIONS FROM DIESEL LOCOMOTIVE AND ELECTRIC  
LOCOMOTIVE POWER SOURCE (tons/year)<sup>a</sup>

Emissions	Diesel Locomotive	Electric Locomotive <sup>b</sup>
Particulates	23	-
Sulfur dioxide (SO <sub>2</sub> )	24	45
Carbon monoxide (CO)	123	-
Hydrocarbons	89	-
Nitrogen oxides (NO <sub>x</sub> )	351	160

Source: Bechtel 1975.

<sup>a</sup> Diesel emissions measured at ground level. Electric locomotive power source emissions measured 300 feet above ground.

<sup>b</sup> Assumed power provided by coal-fired electrical generating plant that would have to increase boiler size to meet the demand.



million tons/year of coal would have to be mined to make up for the loss and a total of 3.5 million tons/year of coal fines would have to be sold.

Safety specifications require that the conveyors be protected by fire prevention systems. Water supplies, sprays, and detection equipment for such a system would be extensive and almost impossible to maintain.

For safety purposes, it would be necessary to fence the conveyor system. This fence, as well as the conveyor belts themselves, would provide an effective barrier to the movement of big game (particularly pronghorn antelope) and livestock. Since the proposed action would not require construction of a fence, it would not create as great a barrier.

This alternative was therefore eliminated from further consideration because it is less energy efficient and less reliable than the proposed action. In addition, transportation of coal by conveyor belt would result in significantly greater biological impacts than transportation by train.

Trucks. Transportation of coal to the plant in trucks does not provide a reasonable alternative to the proposed action. If 120-ton dump trucks were used for such an operation, a total of approximately 270 trips/day would be required. Since this size vehicle could not operate on public roads, a private haul road would have to be constructed, resulting in essentially the same environmental impacts as the proposed action. Particulate emissions from the trucks are expected to be substantially greater than those generated by the proposed action while emissions of other pollutants would be at least equal to the proposed action. The use of conventional size trucks to supply coal



to the plant is not feasible since more than 6,000 trips/day would be necessary.

#### Water Supply

The following alternative water supplies for the proposed plant were considered.

- water from oil and gas production
- municipal waste water
- Oahe Reservoir water

Oil and gas wells in the vicinity of the proposed project do not produce sufficient production water to meet process needs. Diversion of this water from other basins is prohibited by state law.

Conventional waste water treatment techniques do not reduce the concentration of organic compounds in municipal waste water to a low enough level for this water to be used in the steam generation circuit of the proposed plant. In addition, treated waste water from the communities in the vicinity of the plant must be discharged to a surface drainage; this requirement includes water from underground sources. This is the normal procedure for communities in Wyoming (L.E. Allen, Wyoming State Engineer's Office, personal communication, 1981). In most cases, this water is appropriated to other uses as a part of the surface water supply, and downstream users are dependent on it as a part of the total water supply. For these reasons, this alternative was eliminated from further consideration.

Transportation of water from the Oahe Reservoir in South Dakota to the proposed plant site would require the construction of a pipeline at least 300 miles long. Due to the relatively small quantity of water required for the project, this alternative is not economically feasible.



### Water Supply System

The alternative of transporting water from LaPrele Reservoir to Combs Reservoir by pipeline was considered. However, this was not possible because the project water appropriation stipulates that WyCoalGas transport LaPrele Reservoir water down the natural channels of LaPrele Creek and the North Platte River.

In addition to this requirement, it is apparent that transportation of the water via a pipeline would create more environmental impacts than the proposed action. Construction of the pipeline would cause surface disturbance and stream sedimentation that would not result from the proposed action. As discussed in Chapter Three of the Environmental Impact Statement, the proposed water supply system operating schedule would increase flows in LaPrele Creek and enhance the aquatic habitat. This positive effect would not occur if the water were transported by pipeline.

### Power Production From Excess Coal Fines

As discussed above, approximately 10.8 million tons of coal per year would be delivered from the mine to the plant. Approximately 7.6 million tons would be of a particle size large enough to gasify; the remaining 3.2 million tons would consist of fines too small to use in the gasifiers. Of the fines, approximately 2.6 million tons per year would be used to fire the boilers at the plant; the remaining 0.6 million tons of excess fine would be sold as steam coal. The alternative of installing another package boiler at the plant to produce electricity from the excess coal fines was considered.

Excess fines sold to a local power plant would supplement existing coal sources. Therefore, the only impacts associated with the proposed action and not with this alternative would be from rail transport of the fines from the gasification plant to another location.



Combustion of the fines to produce electricity at the plant would increase boiler-related emissions from the plant and increase project water consumption by approximately 2,000 to 3,000 acre-feet per year. The electricity would have to be sold to a local power company, resulting in a possible increase in the total length of new transmission lines required for the project. The electricity could not be used in the plant since sufficient power would already be produced by the proposed action. The electrical power system of the plant, even with another boiler, would not be adequate to meet the peaking single-phase needs of the railroad.

The net impacts associated with this alternative were considered to be greater than those caused by the proposed action. Therefore, the alternative was eliminated from further consideration.

#### Product Pipeline

Pipeline Routes. In addition to the proposed action, eight alternative pipeline routes were considered that would connect the proposed plant to the existing Panhandle Eastern pipeline system (Figure 5.2-3). Except for route H, all of the alternatives are significantly longer than the proposed action (Table 5.2-3), and would have proportionally greater environmental impacts associated with surface disturbance during construction. All routes except B and H have more major stream crossings than the proposed action (Table 5.2-3). Route B crosses the Stewart Lake National Wildlife Refuge, White Lake National Wildlife Refuge, and Bowman-Haley Reservoir and National Wildlife Refuge (Woodward-Envicon 1973). No national wildlife refuges are crossed by the proposed product pipeline right-of-way. Primarily for these reasons, all of the alternative alignments except Route H were eliminated from further consideration.

Figure 5.2-3. Alternative  
Product Pipeline Routes



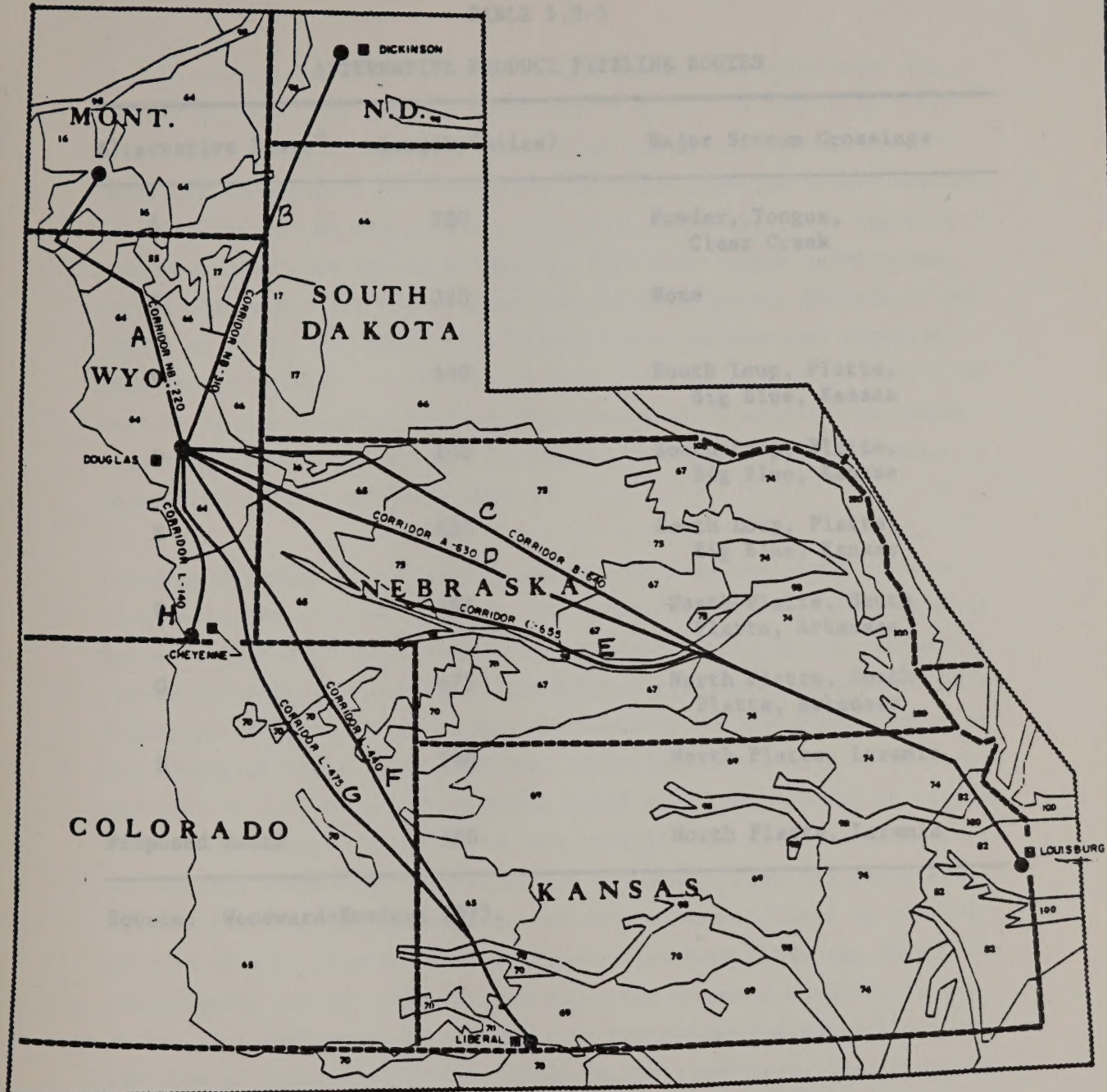


Figure 5.2-3. Alternative Product Pipeline Routes



TABLE 5.2-3

## ALTERNATIVE PRODUCT PIPELINE ROUTES

Alternative Route <sup>a</sup>	Length (miles)	Major Stream Crossings
A	220	Powder, Tongue, Clear Creek
B	310	None
C	640	South Loup, Platte, Big Blue, Kansas
D	630	South Loup, Platte, Big Blue, Kansas
E	655	South Loup, Platte, Big Blue, Kansas
F	440	North Platte, South Platte, Arkansas
G	475	North Platte, South Platte, Arkansas
H	140	North Platte, Laramie
Proposed Route	160	North Platte, Laramie

Source: Woodward-Envicon 1973.



In accordance with the Federal Land Policy and Management Act (FLPMA) of 1976, the BLM has instituted a policy to establish corridors around existing energy transmission and transportation facilities, and to consider new corridors only when location within a compatible distance of existing facilities is infeasible, and where environmental impacts can be mitigated. The U.S. Forest Service has established a similar policy under the National Forest Management Act (NFMA) of 1976. To comply with this policy, the proposed pipeline route would parallel an existing Conoco pipeline for approximately 50 percent of its length. Route H does not parallel an existing transmission corridor over any of its length; therefore, it was eliminated from further consideration.

Pipeline Diameter. As discussed above, the proposed product pipeline would tie into the existing CIG system near the Colorado-Wyoming border. This existing system is operated at a pressure of approximately 750 psig; consequently, the product pipeline must operate at a higher pressure in order for the gas to enter the CIG line. Based on the length of the product pipeline, it would be necessary to discharge gas from the plant at approximately 1,440 psig in order for it to flow into the existing system without the installation of an extra compressor station between the plant and the CIG line. Pipe for gas transmission lines is manufactured in pressure classes. There is a class of pipe with a pressure limit of 1,440 psig; this class was chosen for the proposed action. The CIG system at the proposed intertie is 24 inches in diameter; consequently, this represents the upper limit of the product pipeline diameter. Pipe in the 1,440-psig class below 24 inches in diameter does not have sufficient capacity to transport the proposed volume of gas.

#### Ash Disposal Site

Burial at the plant site of ash produced from process streams was considered as an alternative to the proposed project. Because of increased particulate emissions from plant-site burial, it would not be



possible to obtain an air quality permit to construct, if this alternative were implemented.

Burial of ash at other sites remote from the plant would result in higher particulate emissions than the proposed action. Some additional miles of railroad line would also have to be constructed to the disposal site.

#### Byproduct Storage

The proposed gasification process would generate ammonia and sulfur as byproducts. Ammonia can be stored as a gas or liquid while sulfur can be stored as a liquid or solid.

Ammonia in the quantities to be produced at the plant is essentially always stored in liquid form. Storage in the gaseous state would require the construction of tanks at least an order of magnitude larger in size than those for the proposed action, and would not provide significant environmental or safety advantages; therefore, this alternative was eliminated from further consideration.

Sulfur in the solid state would be stored in blocks. These blocks would be subject to water erosion which could potentially result in increased concentrations of sulfur compounds in local surface and/or groundwaters. This potential impact was considered more significant than impacts associated with the proposed action; therefore, the alternative was eliminated from further consideration.

#### Shipment of Byproducts

Markets have not yet been identified for the byproducts from the gasification plant. Depending on the distance between the plant and eventual market, byproducts may be shipped by truck or rail. The difference in the impacts associated with these two modes of transportation under both normal and nonroutine operating conditions was not



considered large enough for either alternative to be clearly better than the other from an environmental standpoint.

For purposes of the impact assessment, it has been assumed that both byproducts of the process would be shipped by rail, the ammonia to Pocatello, Idaho, and the sulfur to Denver, Colorado. This alternative appeared to be the most reasonable worst-case action.

### 5.3 ALTERNATIVES CONSIDERED FOR DETAILED ANALYSIS

#### Coal Transportation

The relative environmental impacts of transporting coal from the Rochelle Mine to the plant via an existing Burlington Northern (BN) rail line are addressed in Chapter Three of the Environmental Impact Statement. This existing line runs roughly north-south between Gillette and Orin/Shawnee, Wyoming. It ties the BN rail line that parallels Highway 16 in northeastern Wyoming with the BN and Chicago & Northwestern lines that run east-west in the middle of the state (Figure 5.3-1). The line was constructed to transport coal from mines in the eastern Powder River Basin to national markets.

In the vicinity of the proposed project, the BN line passes approximately eight miles west of the Rochelle Mine site, flanks the west side of the Red Hills, and parallels Highway 59 from approximately five miles north of Bill to the proposed plant site (Figure 5.2-1). For this alternative, a spur line would be required from the Rochelle Mine to the existing BN line. Since the BN railroad crosses the property WyCoalGas has leased for the plant, all that would be required for unloading the coal would be a short spur and a loop at the plant site.



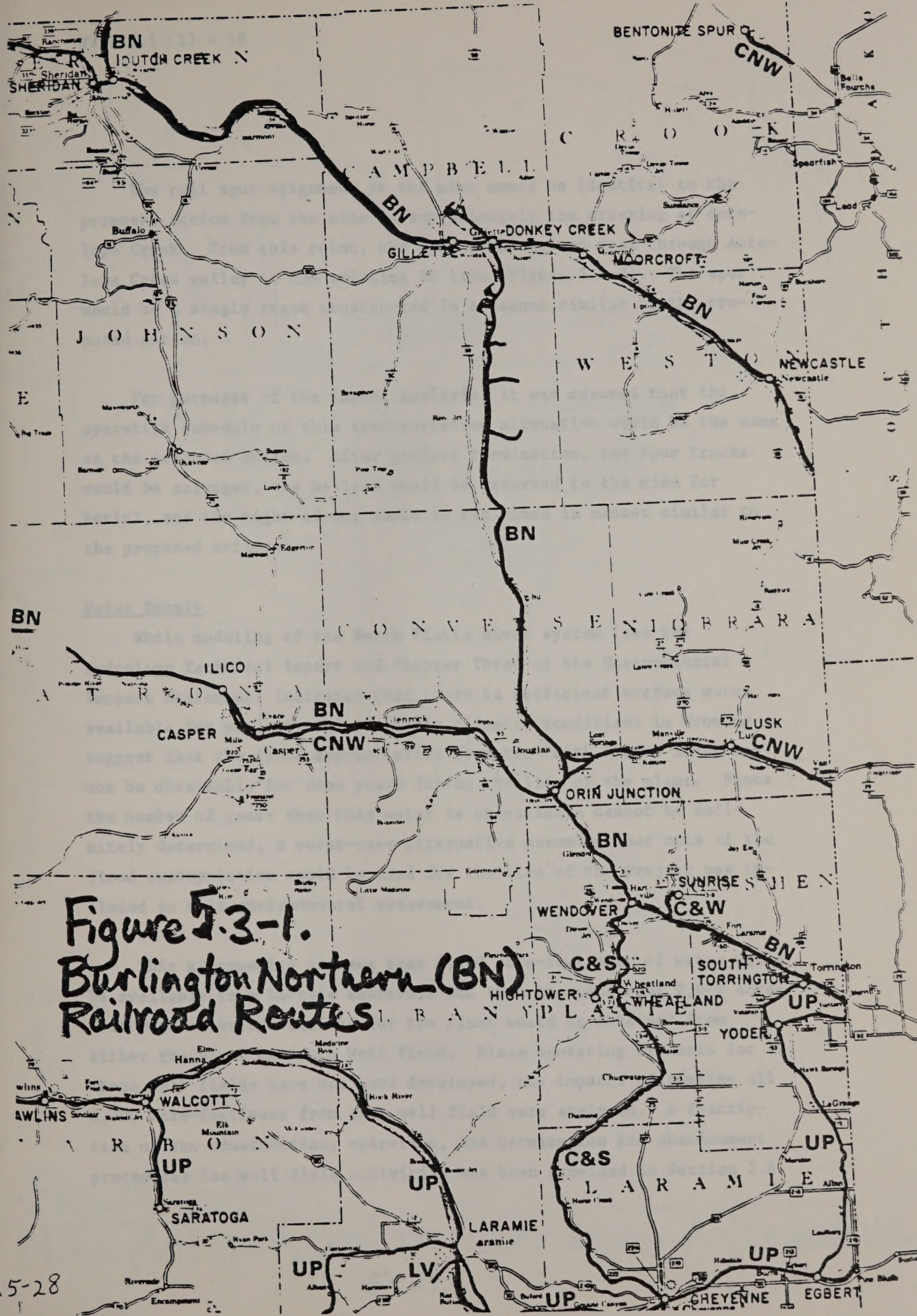


Figure 5.3-1.  
Burlington Northern (BN)  
Railroad Routes



The rail spur alignment at the mine would be identical to the proposed action from the mine to approximately the crossing at Antelope Creek. From this point, the spur would extend west through Antelope Creek valley to the existing BN line (Figure 5.3-2). The spur would be a single track constructed in a manner similar to the proposed action.

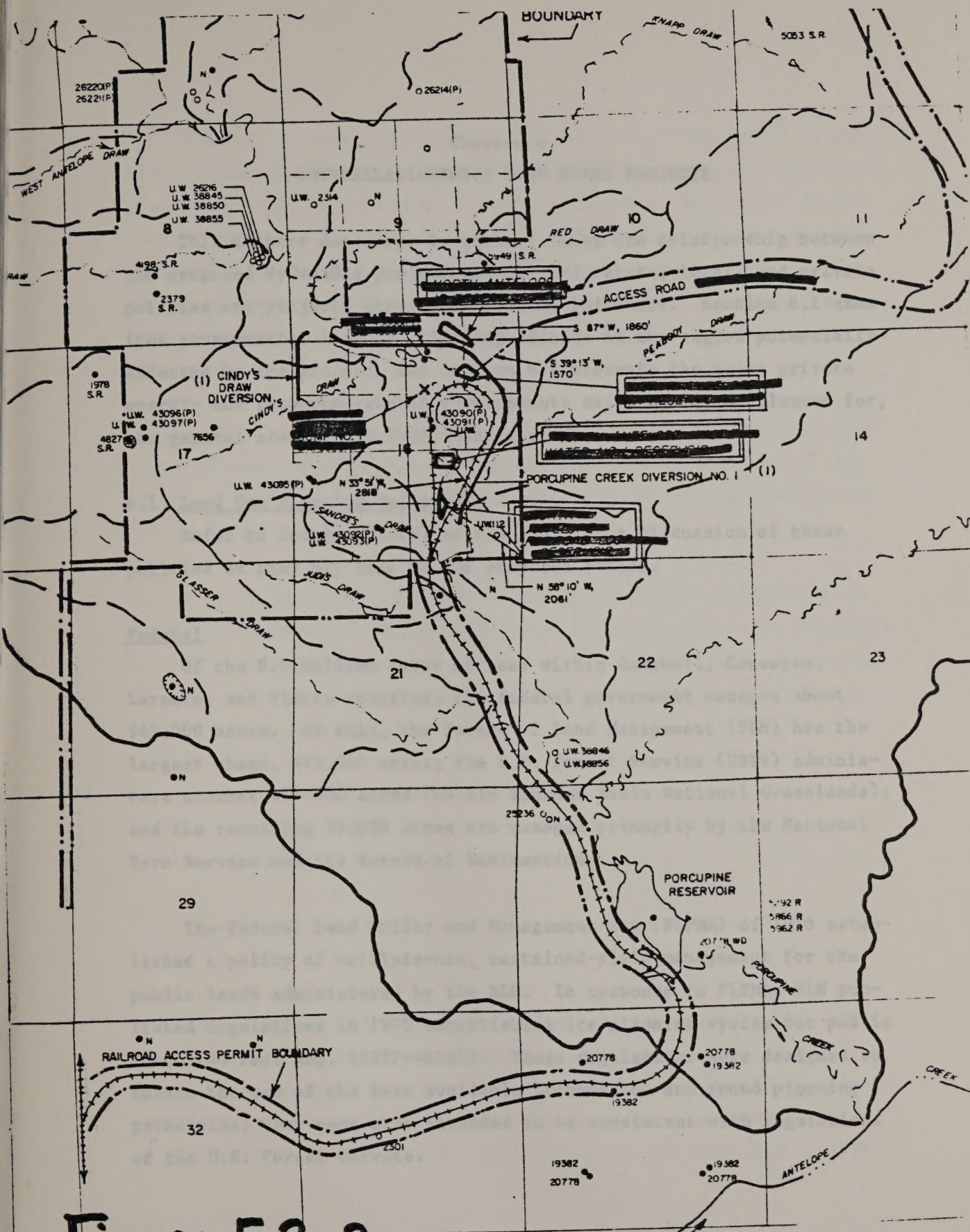
For purposes of the impact analysis, it was assumed that the operating schedule of this transportation alternative would be the same as the proposed action. After project termination, the spur tracks would be salvaged, the ballast would be returned to the mine for burial, and the right-of-way would be reclaimed in manner similar to the proposed action.

#### Water Supply

While modeling of the North Platte River system (see the Hydrology Technical Report and Chapter Three of the Environmental Impact Statement) indicates that there is sufficient surface water available for project needs, erratic climatic conditions in Wyoming suggest that the flood appropriation from the North Platte River may not be obtainable for some years during the life of the plant. Since the number of years when this water is unavailable cannot be definitely determined, a worst-case alternative assuming that none of the flood appropriation could be used for the life of the project was included in this environmental assessment.

This alternative assumes that 4,000 acre-feet/year of water would be available from LaPrele Reservoir and that the remaining 2,000 acre-feet/year of water required for the plant would be obtained from either the North or South Well Field. Since operating criteria for these well fields have not been developed, the impacts of pumping all 2,000 acre-feet/year from each well field were analyzed. A description of the construction, operation, and termination and abandonment procedures for well field activities has been provided in Section 3.6.





**Figure 5.3-2.**  
**Mine Rail Spur, Coal Transportation Alternative**  
 R.70W.  
 5-30



## Chapter 6

## INTERRELATIONSHIPS WITH OTHER PROJECTS

This chapter describes in general terms the relationship between the proposed WyCoalGas project and federal, state, local, and private policies and projects within its area of influence. Section 6.1 examines governmental land-use planning efforts in the region potentially affected by the project, and Section 6.2 presents the major private energy- and resource-related developments existing in, or planned for, the general area of the WyCoalGas proposal.

### 6.1 Land Use Planning Policies

Refer to Section 3.8(E) of the EIS, for a discussion of these policies as they may bear on the proposed action.

#### Federal

Of the 8.9 million acres of land within Campbell, Converse, Laramie, and Platte counties, the federal government manages about 949,000 acres. Of this, the Bureau of Land Management (BLM) has the largest share, 473,000 acres; the U.S. Forest Service (USFS) administers another 417,000 acres (mainly Thunder Basin National Grasslands); and the remaining 59,000 acres are managed primarily by the National Park Service and the Bureau of Reclamation.

The Federal Land Policy and Management Act (FLPMA) of 1976 established a policy of multiple-use, sustained-yield management for the public lands administered by the BLM. In response to FLPMA, BLM published regulations in 1979 establishing its planning system for public lands (44 Fed. Reg. 46387-46388). These regulations were designed to ensure the use of the best available information and sound planning principles; they were also intended to be consistent with regulations of the U.S. Forest Service.



Although resource management planning under FLPMA is just beginning, public lands administered by the BLM in northeast Wyoming are covered by existing land management plans known as Management Framework Plans (MFPs), developed prior to the passage of FLPMA; implementation of the planning procedures under the new regulations will be phased in over the next four years. Decisions of the Eastern Powder River Basin MFP pertaining to the proposed project area include the following:

- To manage mineral resources for efficient development, giving priority consideration to energy minerals, but at the same time providing environmental protection and consideration of socioeconomic impacts.
- To establish corridors around existing energy transmission and transportation facilities, and to consider new corridors only when location within a compatible distance of existing facilities is infeasible, and where environmental impacts can be mitigated.
- To confine new development to an area with high potential for successful reclamation, and to minimize impacts on deer and antelope, and on other resources.
- To reduce visual impacts in mineral development areas (BLM 1977).

The Forest and Rangeland Renewable Resources Planning Act (RPA) of 1974 requires the USFS to assess and inventory National Forest System lands every 10 years, and to recommend to the President every 5 years a Renewable Resources Program for management and administration of the National Forest System. Such a program was completed in 1980.



The National Forest Management Act (NFMA) of 1976 amended the RPA. In response to NFMA, the Secretary of Agriculture in 1979 issued land and resource management planning regulations, including specific directions to the USFS for the preparation of management plans. The new integrated management plans must be completed by the end of 1985. Public participation, and coordination with other federal agencies and with state and local governments, is required during preparation of the plans (Council on Environmental Quality 1980). The management plan for Thunder Basin National Grasslands is expected to be completed in draft form by the end of 1981. The plan will address surface protection and rehabilitation measures required in connection with coal resources and related right-of-way development (USFS 1981).

#### State

As part of the Organic Act of July 25, 1868 (the act admitting Wyoming to the Union), several thousands of acres of land were conveyed to the State of Wyoming, including Sections 16 and 36 of every township for educational purposes. The Wyoming Commission of Public Lands is responsible for the sale, lease, and management of all lands owned by the state and may by state law perform certain land use activities, including appraisal and classification of state lands for agricultural and grazing rentals and sales; leasing of state lands for agricultural, industrial, commercial, and recreational purposes; and the regulation of mining operation on state lands (Wyoming State Land Use Commission 1979).

#### County

Under Wyoming statutes, counties may enforce certain land use controls in unincorporated areas, in matters not specifically reserved to the state. These include regulation of the location and use of buildings and structures, and the use of lands for residence, recreation, agriculture, industry, commerce, public use, and other purposes.



The authority does not apply to lands used for the extraction or production of minerals. The county may also regulate the subdivision of land in unincorporated areas throughout the county (Planning and Zoning Commission, Chapter 18-5-201 through 18-5-207 and Real Estate Subdivisions, Chapters 18-5-301 through 18-5-315).

In 1976 Converse County adopted subdivision and development regulations and in 1978 developed a comprehensive land use plan for the unincorporated areas of the county. In the comprehensive plan, the primary use for all land north of the North Platte River was identified as agriculture. Mineral extraction was designated as the secondary use for this land. To minimize the potential conflicts between mineral extraction and surface uses, the county has attempted to discourage noncompatible uses (e.g., residential and commercial) in areas underlain by known mineral deposits (Converse Area Planning Office 1978). To date the county has not passed a zoning ordinance for all areas of the county.

Campbell County adopted subdivision and zoning regulations for a 5-mile by 6-mile area, roughly centered around Gillette, known as the "Planning District." In 1974 the subdivision regulations were revised to include the remaining areas of the county, and in 1978 a comprehensive planning program was established for the entire county. Currently, the Planning District remains the only county area that is zoned (City of Gillette/Campbell County Department of Planning and Development 1978).

Both Platte and Laramie counties have adopted subdivision regulations and developed comprehensive land use plans. Platte County is completely zoned, with unincorporated areas designated primarily for agriculture. The only unincorporated area in Laramie County that is zoned is within roughly a 5-mile radius of the city of Cheyenne.



## 6.2 Existing and Future Projects in the Area

Tables 6.2-1 and 6.2-2 present, respectively, existing and future private energy- and resource-related projects whose areas of influence may overlap with that of the proposed WyCoalGas project. Locations of these projects are shown in Figures 6.2-1 and 6.2-2. For purposes of this presentation, a "future" project is defined as one which, if constructed, is projected to have production underway in 1981 or later; this definition includes projects which have been constructed but whose operation has been postponed or suspended until 1981 or later. The distinction is based on the start of operation rather than construction, as the former generally initiates more prominent environmental effects.

With certain exceptions, the analysis of cumulative impacts in Chapter 3 of the PDEIS considers discipline-specific subsets of the future projects in Table 6.2-2.

The economic base of Campbell County is dominated by the coal industry. Projections of future coal development in Campbell County show a greater than threefold increase in production by 1995 if currently reported company plans are realized. Baseline forecasts of economic activity in Converse County include stable growth in oil and gas development until 1990; implementation of NERCO's Antelope Coal Mine and PRLA coal mines; and a rapid decline in uranium mining and milling. Further discussion of these forecasts and related socioeconomic concerns may be found in the accompanying Socioeconomics Technical Report and in Chapter 3 of the EIS.



TABLE 6.2-1

EXISTING<sup>a</sup> ENERGY AND RESOURCE RELATED PROJECTS IN THE VICINITY OF THE PROPOSED PROJECT

Project Name	Company	Location <sup>b</sup>	County	Project	Map Reference <sup>c</sup>
Dave Johnston Power Plant	Pacific Power and Light	T. 34 N., R. 76 W. (6 mi. east of Glenrock)	Converse	Power Plant	1
Laramie River Station	Missouri Basin Power Project	T. 25 N., R. 67 W. (5 mi. northeast of Wheatland)	Platte	Power Plant	2
Neil Simpson Power Plant	Black Hills Power & Light	T. 50 N., R. 71 W. (7 mi. east of Gillette)	Campbell	Power Plant	3
Osage Power Plant	Black Hills Power & Light	T. 46 N., R. 63 W. (Osage)	Weston	Power Plant	4
Wyodak Power Plant	Pacific Power and Light	T. 50 N., R. 71 W. (7 mi. east of Gillette)	Campbell	Power Plant	5
Amoco Refinery	Amoco Oil Company	T. 33 N., R. 79 W. (Casper)	Natrona	Petroleum Refinery	6
C & H Refinery	C & H Refinery	T. 32 N., R. 63 W. (Lusk)	Niobrara	Petroleum Refinery	7
Glenrock Refinery	Glenrock Refinery, Inc.	(Glenrock)	Converse	Petroleum Refinery	8
Little America Refinery	Little America Refinery Co.	T. 34 N., R. 78 W. (Casper)	Natrona	Petroleum Refinery	9
Osage Refinery	Glacier Park Co. (Burlington Northern, Inc.)	T. 46 N., R. 63 W. (Osage)	Weston	Petroleum Refinery	10
Texaco Refinery	Texaco, Inc.	T. 34 N., R. 79 W. (Casper)	Natrona	Petroleum Refinery	11
Wyoming Refinery Company Petroleum Refinery	Hamilton Bros. Petroleum	T. 45 N., R. 61 W. (Newcastle)	Weston	Petroleum Refinery	12
Bear Creek Mine and Mill	Bear Creek Uranium Co. (Rocky Mountain Energy)	T. 38 N., R. 73 W. (Northeast of Glenrock)	Converse	Surface Uranium Mine and Mill	13
Highland Mine and Mill	Exxon Minerals Company	T. 36 N., R. 72 W. (23 mi. northwest of Douglas)	Converse	Combination Surface Underground Uranium Mine and Mill	14
Irigaray	Wyoming Minerals Corporation	T. 45 N., R. 77 W. (55 mi. southeast of Buffalo)	Johnson	In Situ Uranium Mine	15
Belle Ayr Mine	Amax Coal Company	T. 48 N., R. 71 W. (18 mi. southeast of Gillette)	Campbell	Coal Strip Mine	16
Big Horn Strip Mine	Peter Kiewit and Sons	T. 57 N., R. 84 W. (8 mi. north of Sheridan)	Sheridan	Coal Strip Mine	17
Black Thunder Mine	Thunder Basin Coal Co. (ARCO)	T. 43 N., R. 70 W. (48 mi. southeast of Gillette)	Campbell	Coal Strip Mine	18
Caballo Mine	Carter-Exxon	T. 48 N., R. 70 W. and 71 W. (17 mi. south of Gillette)	Campbell	Coal Strip Mine	19
Clovis Point Mine	Kerr-McGee	T. 50 N., R. 71 W. (4 mi. east of Gillette)	Campbell	Coal Strip Mine	20
Cordero Strip Mine	Cordero Mining Company	T. 47 N., R. 71 W. (22 mi. south of Gillette)	Campbell	Coal Strip Mine	21
Dave Johnston Mine	Glenrock Coal Company (NERCO)	T. 36 N., R. 75 W. (14 mi. north of Glenrock)	Converse	Coal Strip Mine	22



TABLE 6.2-1 Concluded

Project Name	Company	Location <sup>b</sup>	County	Project	Map Reference <sup>c</sup>
Eagle Butte Mine	Amax	T. 51 N., R. 72 W. (6 mi. north of Gillette)	Campbell	Coal Strip Mine	23
Fort Union Mine	Fort Union Mine Partnership	T. 51 N., R. 71 W. (7 mi. northeast of Gillette)	Campbell	Coal Strip Mine	24
Jacobs Ranch Mine	Kerr-McGee	T. 43 N., R. 70 W. (50 mi. southeast of Gillette)	Campbell	Coal Strip Mine	25
Rawhide Mine	Carter-Exxon	T. 51 N., R. 72 and 73 W., T. 52 N., R. 72 W. (8 mi. north of Gillette)	Campbell	Coal Strip Mine	26
Wyodak Mine	Black Hills Power & Light	T. 50 N., R. 71 W. (7 mi. east of Gillette)	Campbell	Coal Strip Mine	27
Benton Clay	Benton Clay Co.	T. 45 N., R. 82 W. (Mayoworth)	Johnson	Bentonite Mine	28
Bentonite Mill	Benton Clay Co.	(Mills)	Natrona	Bentonite Mine and Mill	29
Bentonite Mine and Mill	American Colloid Company	T. 58 N., R. 64 W. (Northeast corner of Crook County)	Crook	Bentonite Mine and Mill	30
Bentonite Mine and Mill	International Minerals and Chemi- cal Corporation	(Northeast corner of Crook County)	Crook	Bentonite Mine and Mill	31
Bentonite Mine and Mill	NL Industries - Bariod Petroleum Services	(Northeast corner of Crook County)	Crook	Bentonite Mine and Mill	32
Colony Plant Mine and Mill	Federal Bentonite Company	(Colony)	Crook	Bentonite Mine and Mill	33
Kaycee Bentonite Mine	Kaycee Bentonite Corporation	T. 44 N., R. 82 W. (Outside of Kaycee)	Johnson	Bentonite Mine	34
Kaycee Mill	Kaycee Bentonite Corporation	T. 33 N., R. 79 W. (Mills)	Natrona	Bentonite Mill	35
Upton Bentonite Mine	American Colloid Corporation	T. 48 N., R. 65 W. (North of Upton)	Weston	Bentonite Mine and Mill	36
Upton Bentonite Mine and Mill	Federal Bentonite Division	T. 48 N., R. 65 W. (3 mi. northwest of Upton)	Weston	Bentonite Mine and Mill	37
Guernsey Railroad Yard	Burlington Northern	(Guernsey)	Platte	Railroad Yard	38

Sources: Wyoming State Office, U.S. Bureau of Land Management; Wyoming Department of Economic Planning and Development, Mineral Development Monitoring System, revised March 1981.

<sup>a</sup>"Existing" projects are defined as those with productive operations underway prior to 1981.

<sup>b</sup>When project encompasses more than one township and range, given location is that of central facility or office.

<sup>c</sup>See Figure 6.2-1.



TABLE 6.2-2  
FUTURE<sup>a</sup> ENERGY AND RESOURCE RELATED PROJECTS IN THE VICINITY OF THE PROPOSED PROJECT

Project Name	Company	Location <sup>f</sup>	County	Project	Proposed Schedule		Map Reference <sup>g</sup>
					Initial Construction	Initial Production	
Antelope Coal Mine	Antelope Coal Co. (NERCO, Inc.)	T. 40 N., R. 70 W. (50 miles north of Douglas)	Converse	Surface Coal Mine	1982	1984	1
Buckskin Mine	Shell Oil Co.	T. 51 N., R. 72 W. (10 miles north of Gillette)	Campbell	Surface Coal Mine	1980	1981	2
Coal Creek Mine	Thunder Basin Coal Co. (ARCO)	T. 46 N., R. 70 W. (30 miles southeast of Gillette)	Campbell	Surface Coal Mine	1980	1982	3
Dry Fork Mine	Cities Service	T. 57 N., R. 71 W. (45 miles north-northeast of Gillette)	Campbell	Surface Coal Mine	1983	1985	4
Dutchman Mine	JMT Co. (Great Plains Resources and Development Co.)	T. 55 N., R. 82 W. (13 miles east-south-east of Sheridan)	Sheridan	Surface Coal Mine	Unknown <sup>b</sup>		5
East Gillette Mine	Kerr-McGee	T. 50 N., R. 71 W. (4 miles east of Gillette)	Campbell	Surface Coal Mine	1982	1984	6
North Antelope Mine	North Antelope Coal Company (Peabody Coal Co.)	T. 41 N., R. 70 W. (55 miles north-northeast of Douglas)	Campbell	Surface Coal Mine	1981	1984	7
North Rochelle Mine	Shell Oil Company	T. 42 N., R. 70 W. (10 miles southeast of Wright)	Campbell	Surface Coal Mine	1983	1985	8
Pronghorn Mine	Mobil Oil Company	T. 47 N., R. 71 W. (20 miles south-southeast of Gillette)	Campbell	Surface Coal Mine	1981	1982	9
Rawhide South Mine	Carter Mining Company (Exxon)	T. 50 N., R. 71 W. and R. 72 W. (5 miles northeast of Gillette)	Campbell	Surface Coal Mine	1981	1983	10
Rojo Caballos Mine	Mobil Oil Company	T. 47 N., R. 71 W. (20 miles south-southeast of Gillette)	Campbell	Surface Coal Mine	1981	1983	11
Wildcat Creek Mine	Pittsburg Midway Coal Company (Gulf Oil)	T. 52 N., R. 73 W. (16 miles northwest of Gillette)	Campbell	Surface Coal Mine	1981	1983	12
Wymo Fuels Mine	Wymo Fuels, Inc.	T. 45 N., R. 70 W. (30 miles south-southeast of Gillette)	Campbell	Surface Coal Mine	1982	1984	13
Campbell County PRLAs					1987	1988	
Belle Fourche	Wold Nuclear		Campbell	Surface Coal Mine			14
East Black Thunder	ARCO		Campbell	Surface Coal Mine			15
South Gillette	Peabody Coal		Campbell	Surface Coal Mine			16
Thunderbird Project	El Paso Energy Resources		Campbell and Johnson	Surface Coal Mine			17
Thunderbird II	Wold and Jenkins		Campbell and Johnson	In Situ Coal Mine			18
Wildcat Creek Area	Consolidation Coal Co.	(North of Gillette)	Campbell	Surface Coal Mine			19
Converse County PRLAs					1990	1992	
Dull Center	Peabody Coal Co.		Converse	Surface Coal Mine			20
Sand Draw	Peabody Coal Co.		Converse	Surface Coal Mine			21
South Antelope	Peabody Coal Co.		Converse	Surface Coal Mine			22
South Powder River	Dixie		Converse	Surface and Under-ground Coal Mines			23
Stevens North	Western Fuels		Converse	Surface Coal Mine			24
Stevens South	Western Fuels		Converse	Underground Coal Mine			25
Sheridan County PRLA	Woodson Oil Properties	(Southeast of Sheridan)	Sheridan	Surface Coal Mine	1988	1990	26
Ulm Project Block							



TABLE 6.2-2 Concluded

Project Name	Company	Location <sup>f</sup>	County	Project	Proposed Schedule		Map Reference <sup>g</sup>
					Initial Construction	Initial Production	
Bill Smith Mine	Kerr-McGee Nuclear Corp.	T. 36 N., R. 74 W. (Northwest of Douglas)	Converse	Underground Uranium Mine	1980 <sup>c</sup>	1986 <sup>c</sup>	27
Charlie Ore Body	Cotter Corporation (Commonwealth Edison)	T. 45 N., R. 77 W. (Pumpkin Buttes)	Johnson	Surface Uranium Mine and Mill	on hold <sup>d</sup>		28
Cleveland-Cliffs In Situ Mines (also called Thunderbird Joint Venture)	PINTEC (Cleveland Cliffs Iron Co., Pioneer Nuclear, Texas Eastern Nuclear, Getty Oil, and Thunderbird Petroleum)	T. 44 N., R. 75 W. (Pumpkin Buttes)	Campbell	In Situ Solution Uranium Mines (2)	on hold <sup>d</sup>		29
Greasewood Creek Mine	Cleveland-Cliffs and Getty Oil	T. 44 N., R. 75 W. (Pumpkin Buttes)	Campbell	Surface Uranium Mine	on hold <sup>d</sup>		30
Moore Ranch Mine and Sand and Rock Mill	Continental Oil Co. and Kerr-McGee	T. 42 N., R. 75 W. (Pumpkin Buttes)	Campbell	Surface Uranium Mine and Mill	on hold <sup>d</sup>		31
Morton Ranch Project	TVA and United Nuclear Corp.	T. 35 N., R. 72 W. (20 miles northwest of Douglas)	Converse	Surface and Underground Uranium Mines and Mill	on hold <sup>d</sup>		32
Nine Mile Lake	Rocky Mountain Energy	T. 35 N., R. 79 W. (9 miles north of Casper)	Natrona	In Situ Uranium Mine	on hold <sup>d</sup>		33
North Butte Mine and Mill	Cleveland-Cliffs Iron Company and Getty Oil	T. 44 N., R. 75 W. (Pumpkin Buttes)	Campbell	Surface Uranium Mine and Mill	on hold <sup>d</sup>		34
Open Pit Mine	Kerr-McGee Nuclear Corp.	T. 37 N., R. 73 W. (Northwest of Douglas)	Converse	Surface Uranium Mine	1980 <sup>c</sup>	1984 <sup>c</sup>	35
Reno Ranch	Rocky Mountain Energy	T. 43 N., R. 73 W. (Southwest of Wright)	Campbell	In Situ Uranium Mine	1985	1986	36
Section 34 Mine	Kerr-McGee Nuclear Corp.	T. 36 N., R. 74 W. (Northwest of Douglas)	Converse	Underground Uranium Mine	1985	1988	37
SPRB Mill	Kerr-McGee Nuclear Corp.	T. 36 N., R. 74 W. (Northwest of Douglas)	Converse	Uranium Mill	1986	1988	38
Teton Exploration In Situ Mine	UNC-Tenton-NEDCO	(30 miles north of Douglas)	Converse	In Situ Uranium Mine (pilot)	1980 <sup>e</sup>	1982	39
Wyodak #2 Power Plant	Pacific Power & Light	T. 50 N., R. 71 W. (7 miles east of Gillette)	Campbell	Power Plant	1981	1987	40
Hampshire Energy Coal Liquefaction Project	Hampshire Energy	T. 48 N., R. 72 W. (14 miles south of Gillette)	Campbell	Coal Liquefaction Plant	1984	1986	41
ETSI Coal Slurry	Energy Transportation Systems, Inc.	(Eastern Wyoming)	Campbell, Weston, Converse, Niobrara, and Goshen	Coal Slurry Pipeline and Associated Facilities	1982	1985	42
Rocky Hill Site	ARCO	T. 44 N., R. 71 W. (Northeast of Reno Jct.)	Campbell	Experimental In Situ Coal Gasification	1981	unknown	43

Sources: Wyoming State Office, U.S. Bureau of Land Management; Wyoming Department of Economic Planning and Development, Mineral Development Monitoring System, revised March 1981.

<sup>a</sup>"Future" projects are defined as those that, if constructed, are projected to have production underway in 1981 or later.

<sup>b</sup>Project is currently on hold (P. Doreil, Great Plains Resources & Development Co., Laramie, personal communication, May 30, 1981).

<sup>c</sup>Existing, but on standby status.

<sup>d</sup>No present production and no current production plans.

<sup>e</sup>Non-commercial production.

<sup>f</sup>When project would encompass more than one township and range, given location is that of central facility or office.

<sup>g</sup>See Figure 6.2-2.



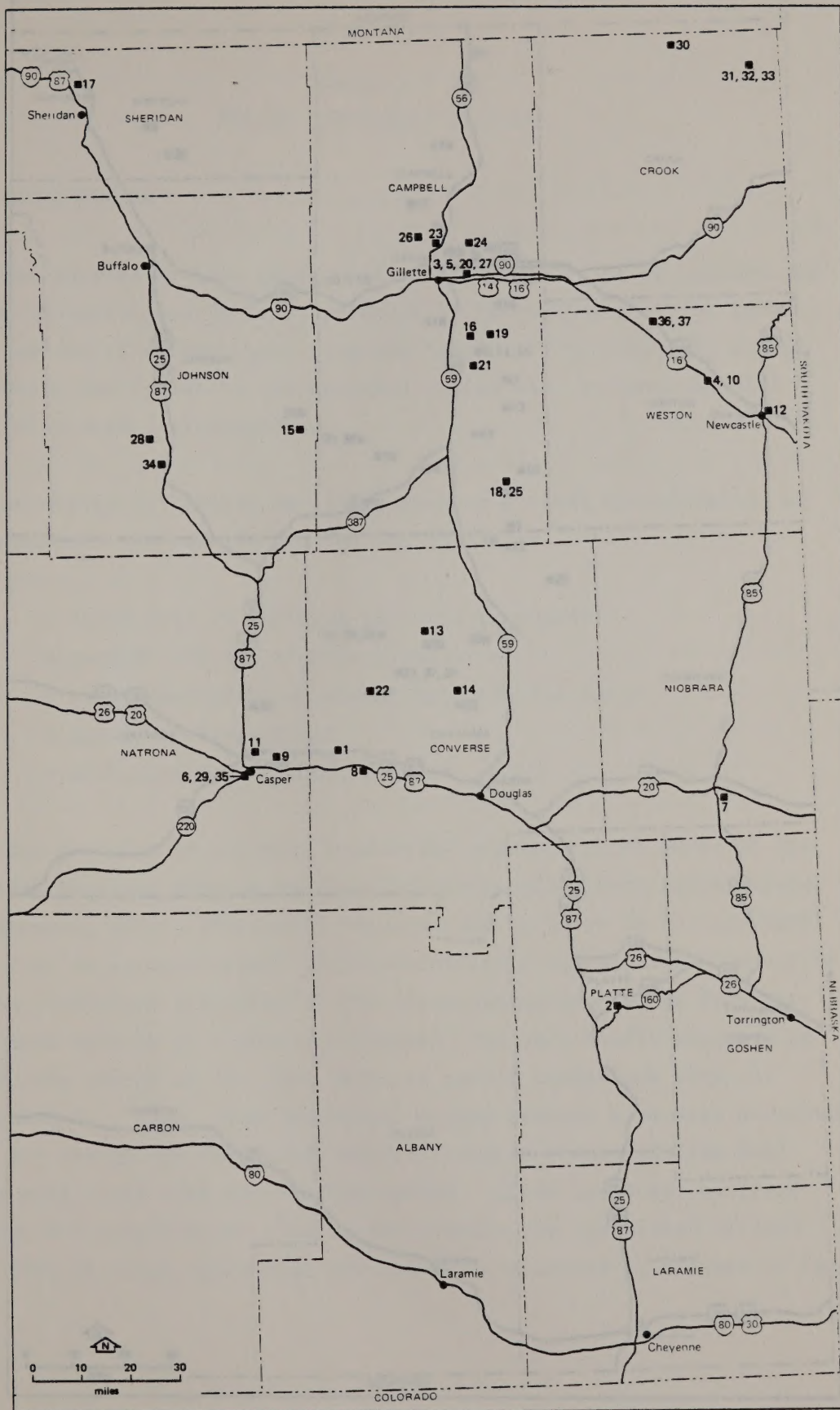


Figure 6.2-1.  
EXISTING PROJECTS IN THE WYCOALGAS PROJECT VICINITY (refer to Table 6.2-1)

6-10



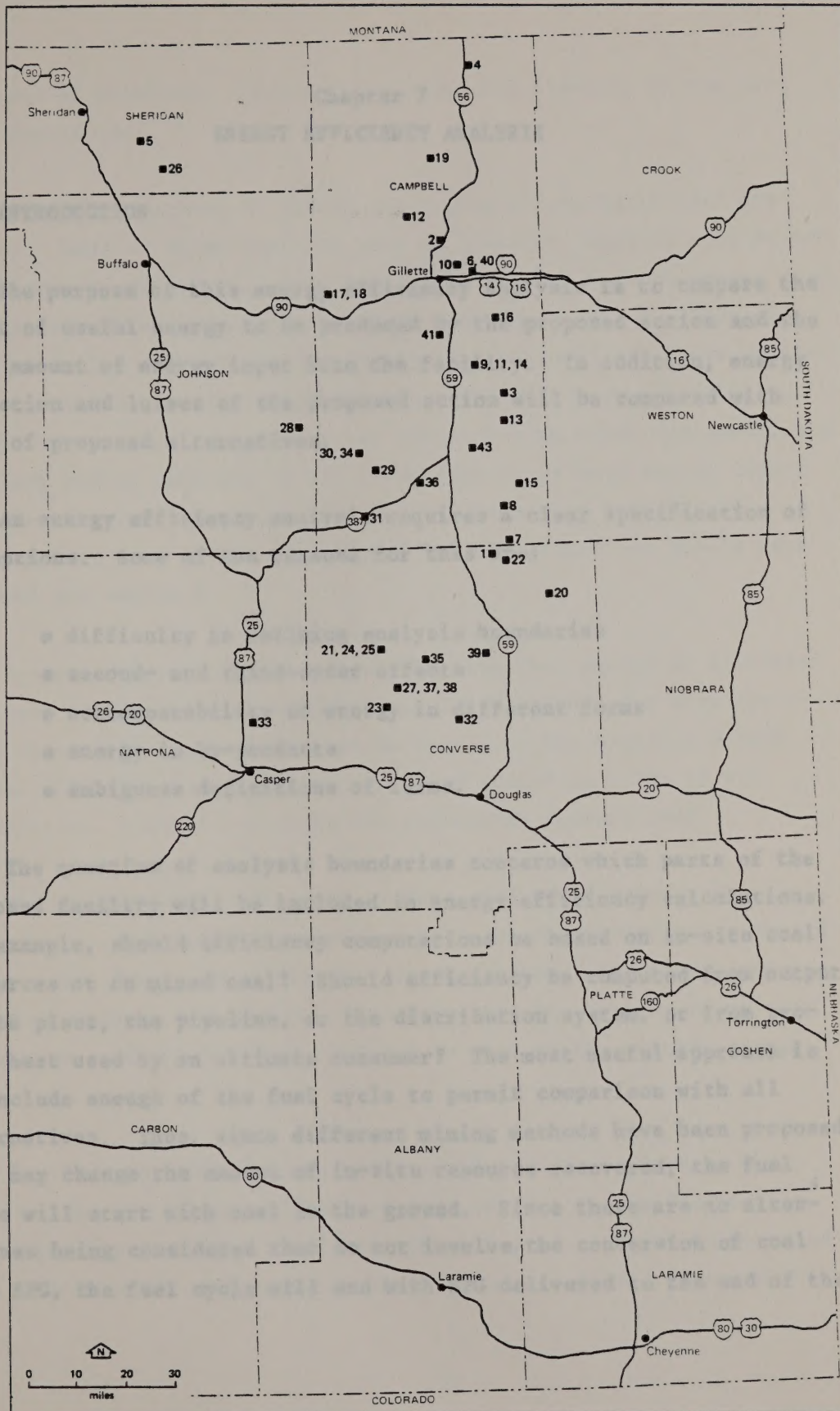


Figure 6.2-2.  
FUTURE PROJECTS IN THE WYOALGAS PROJECT VICINITY (refer to Table 6.2-2)



## Chapter 7

## ENERGY EFFICIENCY ANALYSIS

## 7.1 INTRODUCTION

The purpose of this energy efficiency analysis is to compare the amount of useful energy to be produced by the proposed action and the total amount of energy input into the facility. In addition, energy production and losses of the proposed action will be compared with those of proposed alternatives.

An energy efficiency analysis requires a clear specification of assumptions. Some of the reasons for this are:

- difficulty in defining analysis boundaries
- second- and third-order effects
- noncomparability of energy in different forms
- energy in by-products
- ambiguous definitions of terms.

The question of analysis boundaries concerns which parts of the proposed facility will be included in energy efficiency calculations. For example, should efficiency computations be based on in-situ coal resources or on mined coal? Should efficiency be computed from output at the plant, the pipeline, or the distribution system, or from process heat used by an ultimate consumer? The most useful approach is to include enough of the fuel cycle to permit comparison with all alternatives. Thus, since different mining methods have been proposed that may change the amount of in-situ resource recovered, the fuel cycle will start with coal in the ground. Since there are no alternatives being considered that do not involve the conversion of coal into SPG, the fuel cycle will end with SPG delivered to the end of the



transmission pipeline. Figure 7.1-1 shows the elements of the fuel cycle considered.

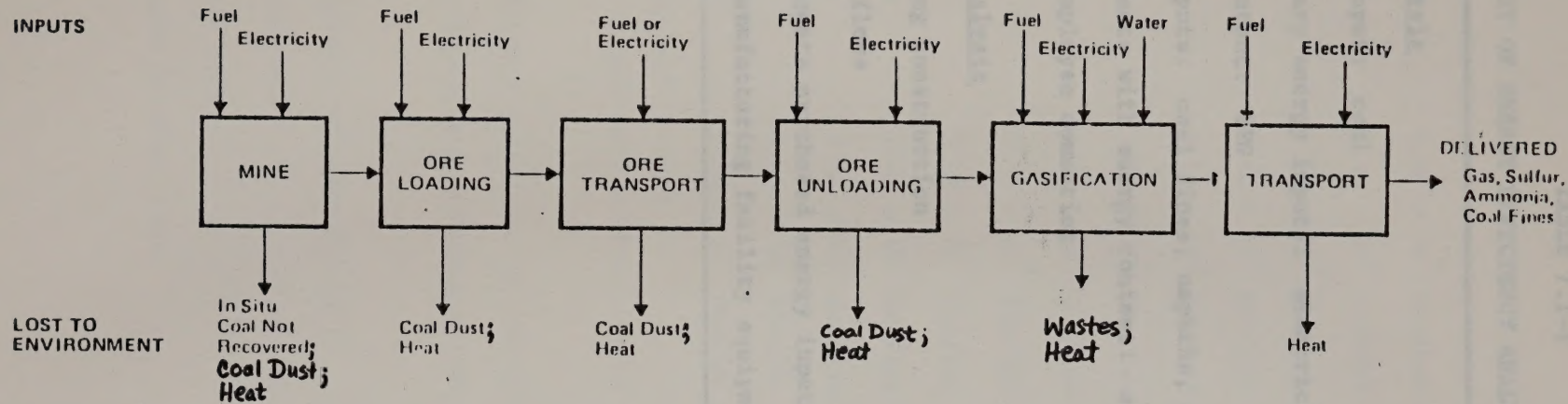
Energy is consumed in almost every step of synthetic fuel production. Some of these uses are easy to identify, such as coal burned or electricity purchased. Others are more subtle, such as energy used in construction or in making the steel used in the plant. This analysis will look only at primary energy inputs (coal) and major ancillary inputs (electricity, diesel fuel, gasoline) to the fuel cycle. Energy for construction, energy for manufacturing plant equipment, and secondary energy consumed in the production of primary energy inputs (e.g., coal burned to create electricity) have been specifically excluded from this analysis. Table 7.1-1 summarizes the energy uses included and excluded.

Energy analyses often overlook the fact that energy in different forms may not be directly comparable. This analysis has been structured so that Btu equivalents can be traced to the original energy inputs. The final results have also been stated in terms of Btu equivalents. Table 7.1-2 shows the conversion factors used.

The proposed facility would produce sulfur and ammonia as by-products. Both of these products have an energy content, although they are not fuels; and since they are marketable, the energy contained in them is not wasted. Therefore, the Btu content of marketable by-products has been included as part of the plant's energy output.

For this analysis "energy efficiency" will be defined as the ratio of the Btu content of all saleable outputs to the Btu content of all primary and major ancillary energy inputs. It should be noted that this does not correspond to what is usually termed "process





7.1-1  
Figure 7.1-1 SYSTEM FLOW FOR ENERGY EFFICIENCY ANALYSIS



TABLE 7.1-1

## SUMMARY OF ENERGY EFFICIENCY ANALYSIS BOUNDARIES

Included in Analysis

Primary energy input: coal

Purchased ancillary energy inputs: electricity, diesel fuel, gasoline

Primary energy output: SPG

Other energy outputs: coal fines, naphtha, etc.

Saleable by-products with energy content: sulfur, ammonia

Energy used in employee commuting

Excluded from Analysis

Energy used during construction

Internal energy flows

Energy used to create purchased energy inputs

Energy used in manufacturing facility equipment

Plant Capacity Factor = .85

## Sources:

<sup>a</sup>Wycoline preliminary technical information 1981.<sup>b</sup>Frank's Standard Handbook for Mechanical Engineering 1978.<sup>c</sup>Text 1957.<sup>d</sup>Handbook of Chemistry and Physics 1970.<sup>e</sup>Perry and Chilton 1973.<sup>f</sup>Superintendence of Mines 1970.

Note: All tonnages in short tons.



TABLE 7.1-2

## ENERGY CONVERSION FACTORS

---

Coal <sup>a</sup>	$1.69 \times 10^7$ Btu/ton	(8,448 Btu/lb)
Electricity <sup>f</sup>	$3.41 \times 10^3$ Btu/kWh	
Gasoline <sup>b</sup>	$1.28 \times 10^5$ Btu/gal	
Diesel Fuel <sup>b</sup>	$1.44 \times 10^5$ Btu/gal	
SPG <sup>a</sup>	$9.70 \times 10^2$ Btu/scf	
Sulfur <sup>a</sup>	$7.37 \times 10^6$ Btu/ton	
Ammonia <sup>a</sup>	$1.81 \times 10^7$ Btu/ton	
Phenol <sup>d</sup>	$2.79 \times 10^7$ Btu/ton	
Naphtha <sup>c</sup>	$3.46 \times 10^7$ Btu/ton	
Tar Oils <sup>c</sup>	$3.27 \times 10^7$ Btu/ton	
Tar <sup>c</sup>	$3.43 \times 10^7$ Btu/ton	
Hydrogen <sup>c</sup>	$5.35 \times 10^4$ Btu/lb	(149 Btu/scf)
Carbon Monoxide <sup>e</sup>	$4.34 \times 10^3$ Btu/lb	(339 Btu/scf)
Plant Capacity Factor <sup>a</sup>	= .91	

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## Sources:

<sup>a</sup>WyCoalGas preliminary technical information 1981.<sup>b</sup>Mark's Standard Handbook for Mechanical Engineering 1978.<sup>c</sup>Kent 1957.<sup>d</sup>Handbook of Chemistry and Physics 1970.<sup>e</sup>Perry and Chilton 1973.<sup>f</sup>Conversion factor only.

Note: All tonnages in short tons.



efficiency." Section 7.2 presents the energy efficiency analysis for the proposed project, both by component and as a whole. Section 7.3 similarly examines alternatives to the proposed action.

## 7.2 ANALYSIS OF PROPOSED ACTION

### 7.2.1 ROCHELLE MINE

The coal mine would provide the main energy input for the coal-to-SPG fuel cycle. For purposes of this analysis, the operation will be taken to include the in-situ resource, coal extraction, crushing and sizing, transportation to the railhead, and loading the coal onto the unit trains.

The mine would have five major energy inputs:

- in-situ coal
- purchased electricity
- purchased diesel fuel
- purchased gasoline
- gasoline used in commuting.

The mine is assumed here to provide all of the needs of the gasification plant (32,600 tons/day) and to sell to no other customers. This means that the mine must produce  $1.08 \times 10^7$  short tons/yr of coal.

The Rochelle Coal Company estimates that 82 percent of the in-situ coal within the permit area would be recovered at the mine. This implies that a total in-situ resource of  $1.32 \times 10^7$  tons/yr would be needed to produce  $1.08 \times 10^7$  tons/yr of deliverable coal. Rochelle



Coal Company has also estimated (see Appendix A) the purchased energy requirements of the mine; these are shown in Table 7.2-1.

In addition, a significant amount of energy would be used by employees commuting to the mine. Table 7.2-2 shows the estimated geographical distribution of employees working at the mine, along with the distances to the mine. Each employee is assumed to make one round trip per day for 250 working days per year. Each employee is assumed to drive his own auto with a fuel consumption of 20 mi/gal. These assumptions imply a total gasoline use of  $3.34 \times 10^5$  gal/year or  $4.27 \times 10^{10}$  Btu/yr. The only output from the mine would be the  $1.08 \times 10^7$  tons/yr of coal delivered to the gasification plant. Table 7.2-3 summarizes the energy efficiency computations for the mine.

#### 7.2.2 RAILROAD

The railroad would transport coal from the mine to the plant. Unit trains of thirty-one 100-ton cars would leave the mine approximately every 2 hours. The distance from the mine to the plant is 40 miles.

WyCoalGas estimates that railroad operations would require the purchase of 90,578,400 kWh of electricity ( $3.09 \times 10^{11}$  Btu) each year. Since  $1.08 \times 10^7$  tons of coal ( $1.83 \times 10^{14}$  Btu) would be transported each year, this is equivalent to 715 Btu/ton-mile. In addition, railroad operations would require 250,000 gallons of diesel fuel ( $2.60 \times 10^{10}$  Btu) per year for major maintenance equipment, including two diesel locomotives. During transportation some coal dust would be lost; this is estimated to be 0.1 percent of the coal shipped, or  $1.08 \times 10^4$  tons/yr ( $1.83 \times 10^{11}$  Btu/yr). Table 7.2-4 summarizes the railroad energy efficiency analysis.



TABLE 7.2-1  
PURCHASED ENERGY, ROCHELLE MINE

	Amount	Btu Equivalent
Electricity	$3.35 \times 10^7$ kWh/yr	$1.14 \times 10^{11}$ Btu/yr
Diesel Fuel	$3.08 \times 10^6$ gal/yr	$4.44 \times 10^{11}$ Btu/yr
Gasoline	$1.83 \times 10^5$ gal/yr	$2.34 \times 10^{10}$ Btu/yr
Other Western County	22	57 <sup>b</sup>
TOTAL	180	275 N.A.

<sup>a</sup>Average travel distance taken equal to distance to Wright.

<sup>b</sup>Average travel distance taken equal to distance to Gillette.



TABLE 7.2-2

## DISTRIBUTION OF EMPLOYEES AT MINE

Locality	Percent of Employees	Total Employees	Distance (miles)
Gillette	35	96	67
Wright	40	110	26
Other Campbell County	5	14	26 <sup>a</sup>
Other Weston County	<u>20</u>	<u>55</u>	<u>67<sup>b</sup></u>
TOTAL	100	275	N.A.

<sup>a</sup> Average travel distance taken equal to distance to Wright.

<sup>b</sup> Average travel distance taken equal to distance to Gillette.

<sup>a</sup> Assumes recovery efficiency of 82 percent.

<sup>b</sup> Excluding uncovered coal.

N/A = Not Applicable.



TABLE 7.2-3

## SUMMARY OF COAL MINE ENERGY EFFICIENCY ANALYSIS

	Amount	Btu Equivalent
<u>Coal Resource</u>		
In-situ Resource	$1.318 \times 10^7$ tons/yr	$2.228 \times 10^{14}$ Btu/yr
Recovered Resource <sup>a</sup>	$1.081 \times 10^7$ tons/yr	$1.832 \times 10^{14}$ Btu/yr
<u>Ancillary Energy Inputs</u>		
Electricity	$3.35 \times 10^7$ kWh/yr	$1.14 \times 10^{11}$ Btu/yr
Diesel Fuel	$3.08 \times 10^6$ gal/yr	$4.44 \times 10^{11}$ Btu/yr
Gasoline	$1.83 \times 10^5$ gal/yr	$2.34 \times 10^{10}$ Btu/yr
Employee Commute (Gasoline)	$3.34 \times 10^5$ gal/yr	$4.27 \times 10^{10}$ Btu/yr
<u>Total Energy Inputs</u> <sup>b</sup>	N/A	$1.838 \times 10^{14}$ Btu/yr
<u>Outputs</u>		
Shipped Coal	$1.081 \times 10^7$ tons/yr	$1.832 \times 10^{14}$ Btu/yr
<u>Energy Lost to Process and Waste Products</u>		
Coal Dust Losses	_____ tons/yr	_____ Btu/yr
Other Losses	N/A	$6.24 \times 10^{11}$ Btu/yr
<u>Ratio of Energy Output to Total Energy Inputs:</u> <sup>b</sup> _____		

<sup>a</sup> Assumes recovery efficiency of 82 percent.<sup>b</sup> Excluding nonrecovered coal.

N/A = Not Applicable.



TABLE 7.2-4

## SUMMARY OF RAILROAD ENERGY EFFICIENCY ANALYSIS

	Amount	Btu Equivalent
<u>Coal Inputs</u>	$1.081 \times 10^7$ tons/yr	$1.832 \times 10^{14}$ Btu/yr
<u>Other Ancillary Inputs</u>		
Electricity	$9.06 \times 10^7$ kWh/yr	$3.09 \times 10^{11}$ Btu/yr
Diesel Fuel	250,000 gal/yr	$3.60 \times 10^{10}$ Btu/yr
<u>Total Energy Inputs</u>	N/A	$1.835 \times 10^{14}$ Btu/yr
<u>Outputs</u>		
Delivered Coal	$1.080 \times 10^7$ tons/yr	$1.830 \times 10^{14}$ Btu/yr
<u>Energy Lost to Process and Waste Products</u>		
Coal Dust Losses	$1.08 \times 10^4$ tons/yr	$1.83 \times 10^{11}$ Btu/yr
Other Losses	N/A	$3.45 \times 10^{11}$ Btu/yr
<u>Ratio of Energy Outputs to Total Energy Inputs:</u>		.997

N/A = Not Applicable.



## 7.2.3 GASIFICATION PLANT

The gasification plant would convert coal into synthetic pipeline gas. For purposes of this analysis, the plant is taken to include all coal handling and processing units, and all support systems at the plant; excluded are the water supply and product transportation systems. The plant would have the following major energy inputs:

- coal from the mine
- diesel fuel
- gasoline
- gasoline used in commuting.

WyCoalGas plans to generate all plant electricity from coal fines. WyCoalGas estimates that  $1.08 \times 10^7$  tons/yr of coal would be needed for the full-scale plant. In addition, the plant would require 84,000 gal/yr of gasoline ( $1.08 \times 10^{10}$  Btu) and 384,000 gal/yr of diesel fuel ( $5.53 \times 10^{10}$  Btu).

The gasoline used by employees commuting to the plant was estimated. Based on Table 7.2-5, the average commuting distance to the plant is estimated to be 27 miles. The peak labor force would be 1,200 people. This along with other assumptions used in Section 7.2.1 implies a total gasoline usage of  $8.21 \times 10^5$  gal/yr ( $1.05 \times 10^{11}$  Btu/yr).

The plant would produce  $3.00 \times 10^8$  scf/day or  $9.96 \times 10^{10}$  scf/yr of SPG ( $9.66 \times 10^{13}$  Btu/yr). In addition, by-products would be produced as shown in Table 7.2-6.

WyCoalGas, Inc., estimates total losses of coal dust in unloading, handling, and processing to be 1,247 tons/yr ( $2.11 \times 10^{10}$  Btu/yr).



TABLE 7.2-5

## DISTRIBUTION OF EMPLOYEES AT PLANT

Locality	Percent of Employees	Total Employees	Distance (miles)
Douglas	73	876	20
Glenrock	20	240	48
Casper	2	24	73
Other Converse Co.	<u>5</u>	<u>60</u>	<u>34<sup>a</sup></u>
TOTAL	100	1200	N.A.

<sup>a</sup> Average travel distance taken equal to the mean of the distances to Douglas and to Glenrock.



TABLE 7.2-6

## Table COAL GASIFICATION BY-PRODUCTS AND HEAT CONTENT

Product	Amount	Btu Content
Sulfur	$2.26 \times 10^4$ tons/yr	$1.76 \times 10^{11}$ Btu/yr
Ammonia	$3.62 \times 10^4$ tons/yr	$6.55 \times 10^{11}$ Btu/yr
Coal Fines	$6.87 \times 10^5$ tons/yr	$1.16 \times 10^{13}$ Btu/yr

significant energy inputs or outputs for the water supply system.

## 7.2.5 PRODUCT TRANSPORTATION

The major product transportation system would be the product pipeline. The system would operate with a single compressor at the plant; the energy for this compressor has been included in the plant analysis. There would be no other major energy inputs for the pipeline. The output would be  $2 \times 10^8$  scf/day of CPG at the terminal of the pipeline.

Process by-products would be shipped by rail. It is assumed that the ammonia would be shipped to Pocatello, Idaho, and the sulfur and unreacted coal fines to Denver, Colorado. Diesel fuel used by freight trains averages 470 Btu/ton-mile. This implies the energy usage shown in Table 7.2-4.

Solid wastes from the plant would be transported back to the mine using the railroad system. Energy for this has been included in the railroad analysis.



Table 7.2-7 summarizes the energy efficiency computations for the plant. Note that this analysis includes the Texaco gasification step. Inclusion of this process alters the balance of outputs, and lowers overall plant efficiency by 2 to 3 percent, in comparison to pure Lurgi technology.

#### 7.2.4 WATER SUPPLY SYSTEM

WyCoalGas estimates that 45,202,000 kWh/yr ( $1.54 \times 10^{11}$  Btu) would be needed for water pumping. There would be no other significant energy inputs or outputs for the water supply system.

#### 7.2.5 PRODUCT TRANSPORTATION

The major product transportation system would be the product pipeline. The system would operate with a single compressor at the plant; the energy for this compressor has been included in the plant analysis. There would be no other major energy inputs for the pipeline. The output would be  $3 \times 10^8$  scf/day of SPG at the terminal of the pipeline.

Process by-products would be shipped by rail. It is assumed that the ammonia would be shipped to Pocatello, Idaho, and the sulfur and excess coal fines to Denver, Colorado. Diesel fuel used by freight trains averages 690 Btu/ton-mile. This implies the energy usage shown in Table 7.2-8.

Solid wastes from the plant would be transported back to the mine using the railroad system. Energy for this has been included in the railroad analysis.



TABLE 7.2-7

## SUMMARY OF PLANT ENERGY EFFICIENCY ANALYSIS

	Amount	Btu Equivalent
<u>Coal Inputs</u>		
Coal to Gasification	$7.58 \times 10^6$ tons/yr	$1.28 \times 10^{14}$ Btu/yr
Coal Fines to Boiler	$2.56 \times 10^5$ tons/yr	$4.36 \times 10^{13}$ Btu/yr
Coal Fines for Sale	$6.87 \times 10^5$ tons/yr	$1.16 \times 10^{13}$ Btu/yr
<u>Total Coal Inputs</u>	$1.08 \times 10^7$ tons/yr	$1.83 \times 10^{14}$ Btu/yr
<u>Ancillary Energy Inputs</u>		
Electricity	None	None
Gasoline	$8.40 \times 10^4$ gal/yr	$1.08 \times 10^{10}$ Btu/yr
Diesel Fuel	$3.84 \times 10^5$ gal/yr	$5.53 \times 10^{10}$ Btu/yr
Employee Commute (Gasoline)	$8.21 \times 10^5$ gal/yr	$1.05 \times 10^{11}$ Btu/yr
Other Ancillary Inputs <sup>a</sup>	--	$4.34 \times 10^{11}$ Btu/yr
<u>Total Energy Inputs</u>		
<u>Outputs</u>		
Product Gas (SPG)	$9.96 \times 10^{10}$ scf/yr	$9.66 \times 10^{13}$ Btu/yr
Coal Fines for Sale	$6.87 \times 10^5$ tons/yr	$1.16 \times 10^{13}$ Btu/yr
Sulfur for Sale	$2.26 \times 10^4$ tons/yr	$1.76 \times 10^{11}$ Btu/yr
Ammonia for Sale	$3.62 \times 10^4$ tons/yr	$6.55 \times 10^{11}$ Btu/yr
Total Usable Energy Outputs	--	$1.09 \times 10^{14}$ Btu/yr
<u>Energy Lost to Process and Waste Products</u>		
Coal Dust Losses	1,247 tons/yr	$2.11 \times 10^{10}$ Btu/yr
Other Losses	--	$7.46 \times 10^{13}$ Btu/yr
<u>Ratio of Energy Outputs to Total Energy Inputs: 0.594</u>		

<sup>a</sup>Process air and water.



TABLE 7.2-8

## BY-PRODUCT SHIPPING ENERGY REQUIREMENTS

Product	Amount (tons/yr)	Distance (miles)	Ton-Miles/Yr	Btu/Yr	Diesel Equivalent (gal/yr)
Sulfur	$2.26 \times 10^4$	295	$6.67 \times 10^6$	$4.60 \times 10^9$	$3.19 \times 10^4$
Ammonia	$3.62 \times 10^4$	741	$2.68 \times 10^7$	$1.85 \times 10^{10}$	$1.28 \times 10^5$
Coal Fines	$6.87 \times 10^5$	205	$1.41 \times 10^8$	$9.73 \times 10^{10}$	$6.76 \times 10^5$
TOTAL	---	---	$1.74 \times 10^8$	$1.20 \times 10^{11}$	$8.36 \times 10^5$

plant using an electric railway system. An alternative is the use of an existing rail line, operated by Burlington Northern Railway, which parallels most of the proposed electric railway.

This alternative would affect only rail operations. The haul distance would be approximately 45 miles, compared to 40 miles for the electric railway. Diesel trains would be used. All other parameters are assumed to be the same, including train size and frequency, and coal dust losses.

Diesel fuel consumption is assumed to be 87.2 Btu/ton-mi (cf. 732 Btu/ton-mi for electric trains). This implies a yearly fuel consumption of  $1.06 \times 10^7$  tons/yr  $\times$  45 mi  $\times$  87.2 Btu/ton-mi  $= 4.23 \times 10^{11}$  Btu/yr, equivalent to  $1.06 \times 10^6$  gal/yr of diesel fuel. An additional  $1.5 \times 10^5$  gal/yr is assumed to be needed for maintenance equipment, as in the proposed action. The alternative and proposed action are compared in Table 7.3-1.

In addition to these direct operational effects, there would be an energy savings with this alternative due to the elimination



## 7.2.6 SUMMARY

The energy inputs and outputs for all components of the proposed action can be combined using the flow outlined in Figure 7.1-1. Table 7.2-9 summarizes the cumulative energy efficiency of the proposed action.

## 7.3 ANALYSIS OF ALTERNATIVES

## 7.3.1 COAL TRANSPORTATION USING EXISTING RAIL CORRIDOR

The proposed action would transport coal from the mine to the plant using an electric railway system. An alternative is the use of an existing rail line, operated by Burlington Northern Railway, which parallels most of the proposed electric railway.

This alternative would affect only rail operations. The haul distance would be approximately 45 miles, compared to 40 miles for the electric railway. Diesel trains would be used. All other parameters are assumed to be the same, including train size and frequency, and coal dust losses.

Diesel fuel consumption is assumed to be 872 Btu/ton-mi (cf. 732 Btu/ton-mi for electric trains). This implies a yearly fuel consumption of  $1.08 \times 10^7$  tons/yr  $\times$  45 mi  $\times$  872 Btu/ton-mi =  $4.23 \times 10^{11}$  Btu/yr, equivalent to  $2.94 \times 10^6$  gal/yr of diesel fuel. An additional  $2.5 \times 10^5$  gal/year is assumed to be needed for maintenance equipment, as in the proposed action. The alternative and proposed action are compared in Table 7.3-1.

In addition to these direct operational effects, there would be an energy savings with this alternative due to the elimination



TABLE 7.2-9

## SUMMARY OF ENERGY EFFICIENCY ANALYSIS OF PROPOSED ACTION

	Amount	Btu Equivalent
<u>Coal Inputs</u>		
In-situ Resource	$1.318 \times 10^7$ tons/yr	$2.228 \times 10^{14}$ Btu/yr
Recovered Resource	$1.081 \times 10^7$ tons/yr	$1.832 \times 10^{14}$ Btu/yr
<u>Other Ancillary Inputs</u>		
Mine: Electricity	$3.35 \times 10^7$ kWh/yr	$1.14 \times 10^{11}$ Btu/yr
Diesel Fuel	$3.08 \times 10^6$ gal/yr	$4.44 \times 10^{11}$ Btu/yr
Gasoline	$1.83 \times 10^5$ gal/yr	$2.34 \times 10^{10}$ Btu/yr
Commute (Gasoline)	$4.27 \times 10^5$ gal/yr	$5.46 \times 10^{10}$ Btu/yr
Railroad: Electricity	$9.06 \times 10^7$ kWh/yr	$3.09 \times 10^{11}$ Btu/yr
Diesel Fuel	$2.50 \times 10^5$ gal/yr	$3.60 \times 10^{10}$ Btu/yr
Plant: Gasoline	$8.40 \times 10^4$ gal/yr	$1.08 \times 10^{10}$ Btu/yr
Diesel Fuel	$3.84 \times 10^5$ gal/yr	$5.53 \times 10^{11}$ Btu/yr
Commute (Gasoline)	$8.21 \times 10^5$ gal/yr	$1.05 \times 10^{11}$ Btu/yr
Other	--	$4.34 \times 10^{11}$ Btu/yr
Water: Electricity	$4.52 \times 10^7$ kWh/yr	$1.54 \times 10^{11}$ Btu/yr
Product Transport: Diesel Fuel	$8.36 \times 10^5$ gal/yr	$1.20 \times 10^{11}$ Btu/yr
Total <sup>a</sup>	N.A.	$1.851 \times 10^{14}$ Btu/yr
<u>Outputs</u>		
Product Gas	$9.96 \times 10^{10}$ scf/yr	$9.66 \times 10^{13}$ Btu/yr
Coal Fines	$6.87 \times 10^5$ tons/yr	$1.16 \times 10^{13}$ Btu/yr
Sulfur	$2.26 \times 10^4$ tons/yr	$1.76 \times 10^{11}$ Btu/yr
Ammonia	$3.62 \times 10^4$ tons/yr	$6.55 \times 10^{11}$ Btu/yr
Total	N.A.	$1.090 \times 10^{14}$ Btu/yr
<u>Energy Lost to Process and Waste Products</u>		
Coal Dust Losses: Mine	$1.08 \times 10^4$ tons/yr	$1.83 \times 10^{11}$ Btu/yr
Railroad	$1.08 \times 10^4$ tons/yr	$1.83 \times 10^{10}$ Btu/yr
Plant	1,247 tons/yr	$2.11 \times 10^{10}$ Btu/yr
Other Losses: Mine	--	$6.24 \times 10^{11}$ Btu/yr
Railroad	--	$3.45 \times 10^{11}$ Btu/yr
Plant	--	$7.46 \times 10^{13}$ Btu/yr
Water	--	$1.54 \times 10^{11}$ Btu/yr
Transport	--	$1.20 \times 10^{11}$ Btu/yr
Total Losses		Btu/yr
<u>Ratio of Outputs to Total Energy Inputs:</u> 0.589		

<sup>a</sup>Based on recovered coal resource.



TABLE 7.3-1

## ENERGY EFFICIENCY COMPARISON: COAL TRANSPORTATION ON BURLINGTON NORTHERN (BN)

	Proposed Action		BN Alternative	
	Amount	Btu Equivalent	Amount	Btu Equivalent
<u>Coal Inputs</u> <sup>a</sup>	$1.081 \times 10^7$ tons/yr	$1.832 \times 10^{14}$ Btu/yr	$1.081 \times 10^7$	$1.832 \times 10^{14}$
<u>Other Ancillary Inputs</u>				
Electricity	$9.06 \times 10^7$ kwh/yr	$3.09 \times 10^{11}$ Btu/yr	negligible	negligible
Diesel Fuel	$2.5 \times 10^5$ gal/yr	$3.60 \times 10^{10}$ Btu/yr	$3.21 \times 10^6$	$4.62 \times 10^{11}$
<u>Total Energy Inputs</u>	-	$1.835 \times 10^{14}$ Btu/yr	-	$1.837 \times 10^{14}$
<u>Outputs</u>				
Delivered Coal <sup>a</sup>	$1.080 \times 10^7$ tons/yr	$1.830 \times 10^{14}$ Btu/yr	$1.080 \times 10^7$	$1.830 \times 10^{14}$
Plant Wastes Returned to Mine <sup>a</sup>				
<u>Energy Lost to Process and Waste Products</u>				
Coal Dust Losses <sup>a</sup>	$1.08 \times 10^{14}$ tons/yr	$1.83 \times 10^{11}$ Btu/yr	$1.08 \times 10^4$	$1.83 \times 10^{11}$
Other Losses		$3.45 \times 10^{11}$ Btu/yr		$4.62 \times 10^{11}$
<u>Ratio of Energy Outputs to Total Energy Inputs :</u>		Proposed Action: .997 BN Alternative: .996		

<sup>a</sup>Negligible change from proposed action.

7-20



of electric railroad construction. Coal dust losses would increase slightly due to the longer haul distance.

### 7.3.2 COAL SUPPLY FROM OTHER MINES

The plant would use coal from the Rochelle Mine. There are other mines in the area that could potentially provide coal for the project. These mines are located generally north of the Rochelle Mine along the Burlington Northern rail line from Gillette to Douglas.

Using coal from an alternative mine would of course change the efficiency of mining; each mine would have different overburden depth, seam thickness, and so on. However, since all of the mines are in the same general area over the same coal formation (the Roland Seam), these differences would not be major, and the same mining techniques would be applicable. Coal characteristics are not expected to vary significantly for mines in the same seam, and the effects on plant efficiency would be minor. Thus, the energy efficiencies for the alternative mine sites should be comparable.

The clearest variations in energy efficiency would arise from railroad operations. Changing the mine location would change the distance the coal must be hauled, thus changing the ancillary energy requirements. The Burlington Northern line is assumed to be used for coal transportation for all mines other than the proposed mine. Approximate rail distances to some mines along the Burlington Northern rail route are shown in Table 7.3-2.

Table 7.3-3 summarizes the increased energy that would be needed to haul coal from each of these mines. The tables are based on a transportation energy requirement of 872 Btu/ton-mi plus 5,952 gal mi-yr for maintenance equipment (equivalent to the 250,000 gal/yr assumed for the 40-mile electric RR).



TABLE 7.3-2

## APPROXIMATE DISTANCES OF AREA MINES FROM PROPOSED PLANT

Mine	Rail Distance
Rochelle (electric RR) <sup>a</sup>	40
Rochelle (BN)	45
North Antelope	42
Black Thunder	51
Jacobs Ranch	54
Coal Creek	64
Cordero	70
Pronghorn	75
Caballo	77

<sup>a</sup>Proposed action.



TABLE 7.3-3

## SUMMARY OF ADDITIONAL ENERGY REQUIREMENTS FOR ALTERNATE COAL SUPPLIES

Mine	Distance to Plant	Electricity	Hauling Diesel	Maintenance Diesel	Total Diesel	Total Btu
Rochelle <sup>a</sup>	42	$9.06 \times 10^7$ kwh	--	$2.50 \times 10^5$ gal	$2.5 \times 10^5$ gal	$3.45 \times 10^{11}$
North Antelope	42	-	$2.75 \times 10^6$	$2.50 \times 10^5$	$3.00 \times 10^6$	$4.32 \times 10^{11}$
Black Thunder	51	-	$3.34 \times 10^6$	$3.04 \times 10^5$	$3.64 \times 10^6$	$5.24 \times 10^{11}$
Jacobs Ranch	54	-	$3.53 \times 10^6$	$3.21 \times 10^5$	$3.85 \times 10^6$	$5.54 \times 10^{11}$
Coal Creek	64	-	$4.19 \times 10^6$	$3.81 \times 10^5$	$4.57 \times 10^6$	$6.58 \times 10^{11}$
Cordero	70	-	$4.58 \times 10^6$	$4.17 \times 10^5$	$4.99 \times 10^6$	$7.19 \times 10^{11}$
Pronghorn	72	-	$4.71 \times 10^6$	$4.29 \times 10^5$	$5.14 \times 10^6$	$7.40 \times 10^{11}$
Belle Ayr	75	-	$4.91 \times 10^6$	$4.46 \times 10^5$	$5.36 \times 10^6$	$7.72 \times 10^{11}$
Caballo	77	-	$5.04 \times 10^6$	$4.58 \times 10^5$	$5.49 \times 10^6$	$7.91 \times 10^{11}$

<sup>a</sup>Proposed action.

7-223



### 7.3.3 GENERATION OF ELECTRICITY FROM EXCESS COAL FINES

The proposed action would generate  $6.88 \times 10^5$  tons/yr of excess coal fines, to be sold. An alternative would be to burn the excess fines to generate further electricity. The electricity could be used in lieu of purchased electricity for the electric railway system and for water transportation. This alternative would affect the energy efficiency of the plant and the product transportation system and would indirectly affect the railroad and water pipeline system.

Assuming a thermal efficiency of 35 percent, the  $6.88 \times 10^5$  tons/yr ( $1.16 \times 10^{13}$  Btu/yr) of coal fines would produce  $4.06 \times 10^{12}$  Btu/yr ( $1.19 \times 10^9$  kWh/yr) of electricity. Assuming a 70 percent capacity factor, this would be equivalent to a rated capacity of about 200 MW. This electricity could be used to supply the railroad ( $9.06 \times 10^7$  kWh/yr) and the water delivery system ( $4.52 \times 10^7$  kWh/yr) and would still leave  $1.05 \times 10^9$  kWh of electricity available for sale to the grid. Transportation energy costs would be reduced by  $9.73 \times 10^{10}$  Btu/yr ( $6.76 \times 10^5$  gal/yr) because the coal fines would not have to be moved to market.

Table 7.3-4 summarizes the effects of this alternative on plant and transportation energy efficiencies.

### 7.3.4 WATER SOURCE ALTERNATIVES

The proposed action would require 8,180 acre-ft per year (AFY) of water to be supplied from the North Platte River and LaPrele Reservoir via storage at Combs Reservoir. This is estimated to require  $4.52 \times 10^7$  kWh/yr (\_\_\_\_\_ Btu/yr). Additional water would be obtained from either the North or South Well Field. Since this additional water would be needed only infrequently, the energy costs are assumed to be negligible.



TABLE 7.3-4

## ENERGY EFFICIENCY COMPARISON: ELECTRICITY PRODUCTION USING COAL FINES

	Proposed Action		Electrical Production Alternative	
	Amount	Btu Equivalent	Amount	Btu Equivalent
<u>Coal Inputs</u>				
Coal to Gasification <sup>a</sup>	7.38 x 10 <sup>6</sup> tons/yr	1.28 x 10 <sup>14</sup> Btu/yr	7.38 x 10 <sup>6</sup>	1.28 x 10 <sup>14</sup>
Coal Fines to Boiler	2.56 x 10 <sup>6</sup> tons/yr	4.36 x 10 <sup>13</sup> Btu/yr	3.25 x 10 <sup>6</sup>	5.49 x 10 <sup>13</sup>
Coal Fines for Sale	6.87 x 10 <sup>5</sup> tons/yr	1.16 x 10 <sup>13</sup> Btu/yr	-	-
Total Coal Inputs	1.08 x 10 <sup>7</sup> tons/yr	1.83 x 10 <sup>14</sup> Btu/yr	1.08 x 10 <sup>7</sup>	1.83 x 10 <sup>14</sup>
<u>Ancillary Energy Inputs<sup>a</sup></u>	-	4.37 x 10 <sup>11</sup> Btu/yr	-	4.34 x 10 <sup>11</sup>
<u>Total Energy Inputs</u>	-	1.834 x 10 <sup>14</sup> Btu/yr	-	1.834 x 10 <sup>14</sup>
<u>Outputs</u>				
Product Gas <sup>a</sup>	9.96 x 10 <sup>10</sup> scf/yr	1.00 x 10 <sup>14</sup> Btu/yr	9.96 x 10 <sup>10</sup>	1.00 x 10 <sup>14</sup>
Coal Fines for sale	6.88 x 10 <sup>5</sup> tons/yr	1.16 x 10 <sup>13</sup> Btu/yr	-	-
Sulfur for sale <sup>a</sup>	2.26 x 10 <sup>4</sup> tons/yr	1.76 x 10 <sup>11</sup> Btu/yr	2.26 x 10 <sup>14</sup>	1.76 x 10 <sup>11</sup>
Ammonia for sale <sup>a</sup>	3.62 x 10 <sup>14</sup> tons/yr	6.55 x 10 <sup>11</sup> Btu/yr	3.62 x 10 <sup>4</sup>	6.55 x 10 <sup>11</sup>
Electricity for sale & use in other systems	-	-	1.19 x 10 <sup>9</sup> kwh/yr	4.06 x 10 <sup>12</sup> Btu/yr
Total usable energy outputs	-	1.124 x 10 <sup>14</sup> Btu/yr	-	1.049 x 10 <sup>14</sup>
<u>Energy Lost to Process &amp; Waste</u>				
<u>Products</u>				
Coal Dust Losses <sup>a</sup>	245 tons/yr	4.13 x 10 <sup>9</sup> Btu/yr	245	4.13 x 10 <sup>9</sup>
Other Losses	-	-	-	-
<u>Ratio of Energy Outputs to Total Energy Inputs</u>	Proposed Action: .613 Alternative: .572			

<sup>a</sup>Negligible change from proposed action.

7-25



Two alternatives have been proposed to this system. The first is to pump 2042 AFY from the North Well Field and the remainder (4138 AFY) from LaPrele Reservoir. The second alternative is similar except that the 2042 AFY would be obtained from the South Well Field.

In the first alternative water would be pumped from the North Well Field at an average rate of 2.82 cfs. Energy requirements for well pumping are assumed to be  $1.56 \times 10^4$  kWh/AF or  $3.182 \times 10^7$  kWh/yr. Water from the North Well Field would be delivered directly to the plant; it is assumed that there is a sufficient pressure head that pumping costs are negligible. The remaining water delivered from LaPrele would have the same per unit energy costs as the proposed action, or  $3.023 \times 10^7$  kWh/yr for the 4138 AFY from this source. Thus the total yearly energy requirements would be  $3.182 \times 10^7 + 3.023 \times 10^7 = 6.205 \times 10^7$  kWh/yr (\_\_\_\_\_ Btu/yr), an increase of 37 percent over the proposed action.

The second alternative would require 2042 AFY from the South Well Field. Well pumping costs for the South Well Field are assumed to be  $2.861 \times 10^3$  kWh/AF or  $5.842 \times 10^6$  kWh/yr. Water from the South Well Field would be pumped to a transfer station near Combs Reservoir and then to the plant. Both pipeline sections are assumed to require  $6.419 \times 10^3$  kWh/AF for a total pipeline energy cost of  $2 \times 6.419 \times 10^3 \times 2042 = 2.622 \times 10^7$  kWh/yr. Thus the total energy cost from the South Well Field would be  $5.842 \times 10^6 + 2.622 \times 10^7 = 3.206 \times 10^7$  kWh/yr. The total energy cost of the alternative (including the 4138 AFY from LaPrele Reservoir) would be  $3.206 \times 10^7 + 3.023 \times 10^7 = 6.229 \times 10^7$  kWh/yr (\_\_\_\_\_ Btu/yr), an increase of 38 percent over the proposed action.

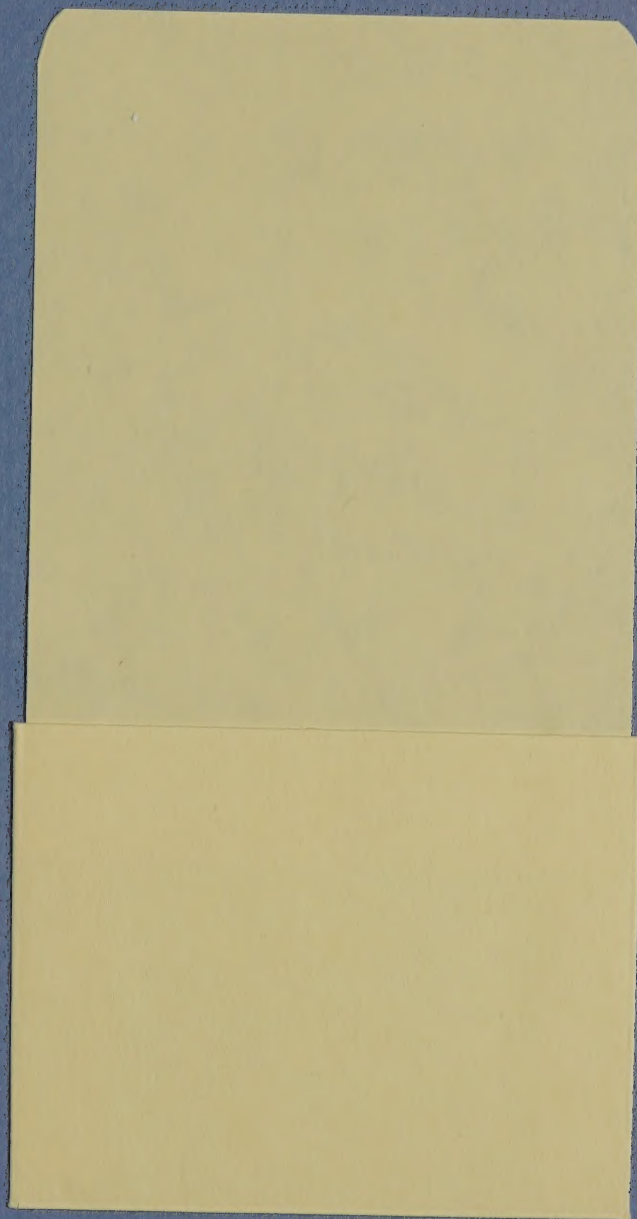


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